Chapter Five: Specific Issues Related to Oil and Gas Exploration, Development, Production and Transportation

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This chapter describes specific issues related to oil and gas exploration, development, production and transportation. These issues include geophysical hazards; transportation of crude oil; oil spill risk, prevention and response; and potential impacts to water quality. Effects on air quality are discussed in Chapter Six.

A. Geophysical Hazards

Primary geophysical hazards in the Cook Inlet and Susitna regions include earthquakes, volcanoes, tsunamis, flooding, ice, current and sediment hazards, and coastal erosion. The area considered in this finding is located in one of the most seismically active regions in the world, is in close proximity to several active volcanoes, and has some of the highest tides in the world. "In spite of these environmental constraints, petroleum extraction and processing facilities have functioned, both onshore and offshore, without significant environmental damage since the Swanson River field was discovered in 1957." (Combellick et al., 1995:1, citing to Magoon and others, 1976).

1. Earthquakes and Faulting

The Cook Inlet trough is a forearc basin between the Aleutian Arc to the west and the Kenai Mountains to the east (Combellick et al., 1995, citing to Kelley, 1985). Subduction of the Pacific crustal plate beneath the Kenai Mountains and Aleutian Arc (North American plate) accumulates crustal stresses that are periodically relieved by deep-focused earthquakes (See Figure 5.1). Other sources of potentially damaging, shallow-focused earthquakes include the active Castle Mountain fault and one possible extension, the Bruin Bay fault, which transect the northwestern margin of the Cook Inlet trough (Combellick et al., 1995:1, citing to Magoon and others, 1976; Hackett, 1977). "A possible southwest extension of the Castle Mountain fault has been mapped along the southeastern flank of Lone Ridge, northwest of Tyonek" (Combellick et al., 1995, citing to Schmoll and others, 1981, 1984; Schmoll and Yehle, 1987). In 1984, a magnitude 5.7 earthquake with an epicenter in the Matanuska Valley, near the town of Sutton was attributed to subsurface movement along the Castle Mountain fault (Combellick et al., 1995, citing to Lahr and others, 1986).

The Bruin Bay fault system consists of a family of four or five echelon faults[1] in a zone as much as 5 miles wide. The fault zone crosses the lease sale area through the northwestern quadrant of T12N, R11W, Seward Meridian and extends more than 250 miles southwest from the Castle Mountain fault west of Anchorage to Becharof Lake on the Alaska Peninsula. The fault plane dips between 45 degrees and vertical, although most of the fault system dips between 60-70 degrees as measured in the Kamishak Bay area. Evidence seems to suggest at least two major movements along this fault system, the first occurring in late Jurassic time (approximately 160 million years ago) and the second more than 25 million years ago during the mid-Cenozoic. The major activity on the main part of the fault system probably ceased during the Oligocene time (approximately 30 million years ago). Offset across the Bruin Bay fault system appears to be dip-slip with a possible strike-slip component. The amount of throw along this system could be as much as 10,000 feet with the southeast block relatively downthrown and a possible left-lateral offset of 12 miles (Meyer, 1993 citing to Detterman and Hartsock, 1966) to 40 miles (Meyer, 1993 citing to Detterman and Reed, 1980). During the 1964 earthquake, the west side of Cook Inlet rose as part of a broad uplift, but no differential uplift took place across the system (Meyer, 1993 citing to Detterman and Reed, 1980).

[1] A grouping of faults that are arranged in a step-like manner.

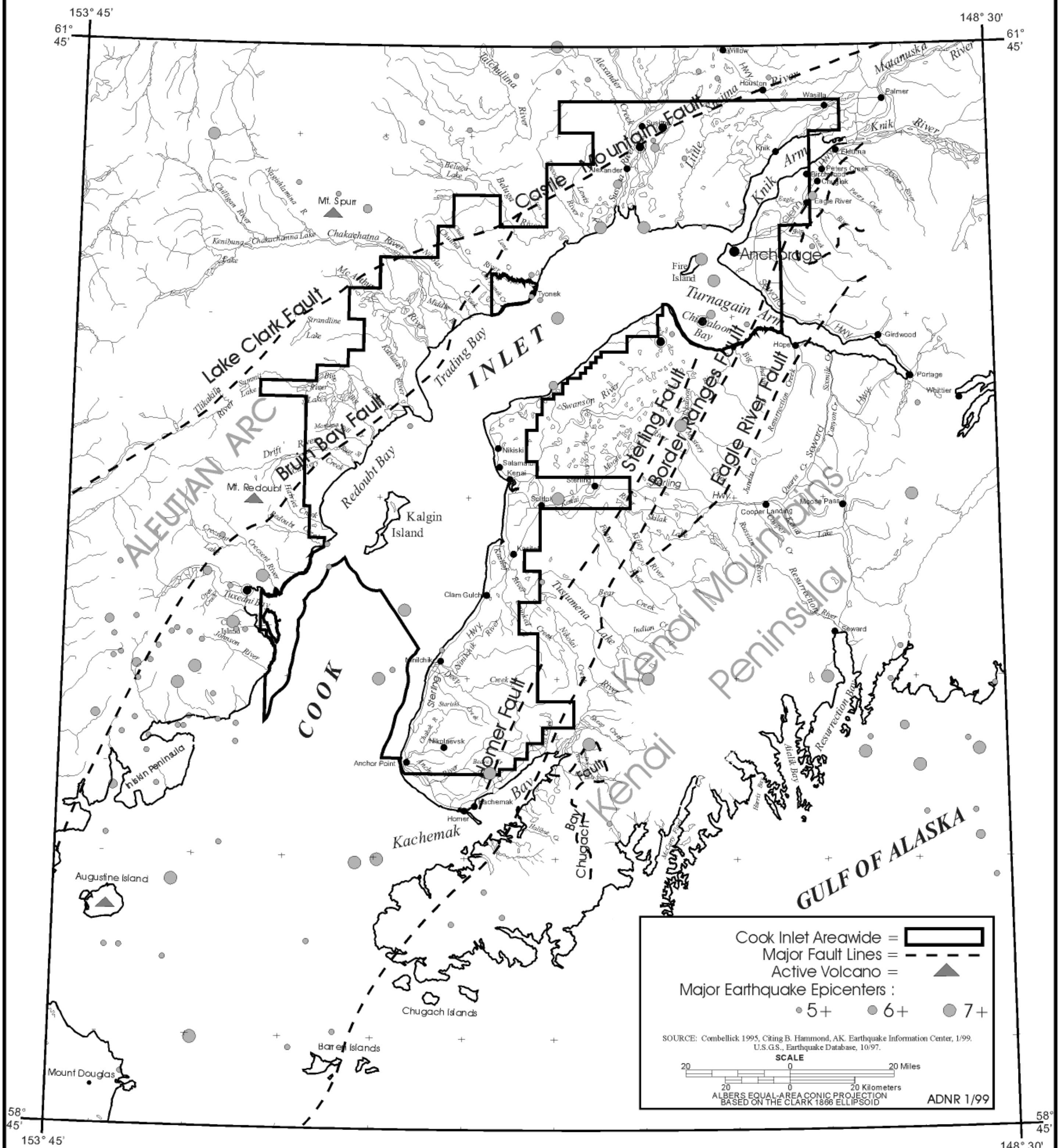

FIGURE 5.1 Geophysical Hazards

The inferred trend of the Bruin Bay fault crosses several townships of the sale area from the vicinity of Tyonek to near Harriet Point on the west side of Cook Inlet (Combellick et al., 1995:1, citing to Magoon and others, 1976). Several northeast-trending faults have been identified or inferred in the western Kenai Lowlands. “Several of these structural breaks are known to cut Tertiary age rocks of the Kenai Group, but they are not known to offset younger deposits and their activities and subsurface extents remain speculative.” (Combellick et al., 1995:1, citing to Barnes and Cobb, 1959; Kirschner and Lyon, 1973; Tysdal, 1976)

The Border Ranges fault is considered a former boundary between the subducted oceanic plate and the continental plate and is considered the eastern boundary of the Cook Inlet basin. The Border Ranges fault forms an arc from Kodiak Island, across the Kenai Peninsula, to the eastern Chugach Mountains, a distance of more than 320 miles. The Border Ranges fault is not exposed along much of the Kenai Peninsula, but it outcrops northeast and east of Anchorage (referred to as the Knik fault) and along Kachemak Bay in the southwestern Kenai Peninsula (Meyer, 1993 citing to MacKevett and Plafker, 1974). The fault plane generally dips between 70 degrees and vertical with the most recent movement along this fault occurring approximately 70 million years ago in the late Mesozoic or early Tertiary time. There is evidence in the Twin Peaks area of the western Chugach Mountains that the Border Ranges fault may have had minor displacement since the Holocene time (10,000 years ago) (Reger, 1993 citing to Reger and Updike, 1983).

Geologic studies indicate that very powerful earthquakes (magnitude 7.8 or greater) have occurred at least once every 525 to 700 years during the past 4,700 years (Reger, 1993 citing to Combellick, 1991, 1992, 1993). Potentially damaging earthquakes (magnitude greater than 5.5) have occurred more frequently. There have been 99 earthquakes with magnitudes of greater than 5.0 in the Cook Inlet region since 1899. Most of these earthquakes had magnitudes of 5.0 to 6.0; four had magnitudes of greater than 7.0 (Combellick, 1995 citing to Reger, 1993).

Diffuse seismicity shallower than 35 km in the Cook Inlet area results from deformation. A 1933 magnitude 6.9 event in Anchorage which caused intensity VII effects on the Mercalli scale[2] may have been related to this shallow deformation. Some buried folds in the upper Cook Inlet area, such as at the Middle Ground Shoal oil field, are cored with blind reverse faults that may be capable of generating magnitude 6.3-6.9 earthquakes (Combellick et al., 1995:1, citing to Haeussler and Bruhn, 1995).

The epicenter of the 1964 earthquake (moment magnitude 9.2) was in Prince William Sound. However, geologic effects were widespread in the lease sale area and included seismic shaking, ground breakage, landslides and other surface displacements, liquefaction, falling objects, and structural failures (Combellick et al., 1995, citing to Waller, 1966; Stanley, 1968; Foster and Karlstrom, 1967; Tysdal, 1976). Future strong earthquakes can be expected to produce similar effects. Studies indicate that very powerful 1964 style earthquakes have occurred with an average recurrence interval of 600-800 years during approximately the past 5,000 years (Combellick, 1994). Smaller great earthquakes in the magnitude 8 range probably have occurred more frequently. The most recent pre-1964 great subduction earthquake in the region was 700-900 years ago (Combellick et al., 1995:3, citing to Combellick, 1993).

Other types of ground failure include liquefaction and sliding of water saturated soils, rockfalls, translatory block sliding such as occurred at Anchorage in 1964, horizontal movement of vibration-mobilized soil which was the cause of extensive damage to Alaskan railways and highways in 1964, and ground fissuring and associated sand extrusions typical of areas where the ground surface is frozen. Extensive occurrence of all these phenomena has been documented for large earthquakes.

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[2] The Mercalli scale measures damage done by an earthquake on a scale from I (not felt) to XII (damage total).

The northern half of the Kenai Peninsula coastline is underlain by till, outwash, and gravely glaciomarine deposits. The southern half is underlain by the Tertiary Beluga formation, which is composed of thinly interbedded layers of sand, shale, and coal. Both of these areas are relatively stable under earthquake loading and should not be compared to the highly unstable sensitive-clay deposits under Anchorage or extensive liquefaction-susceptible sands. Liquefaction of coarse glacial deposits under earthquake loading is probably low, particularly if they remain overconsolidated due to ice loading. However, recent evidence of gravel liquefaction in the Portage area during the 1964 great earthquake indicates that gravel may be more susceptible to liquefaction than previously thought. Site-specific testing of liquefaction susceptibility is advisable (Combellick et al., 1995:6).

The USGS has recently prepared a series of probabilistic seismic hazard contour maps for Alaska, which are available on the USGS Website at http://geohazards.cr.usgs.gov. These maps depict earthquake hazard by showing, by contour values, the earthquake ground motions that have a common given probability of being exceeded in 50 years. The ground motions being considered at a given location are those from all future possible earthquake magnitudes at all possible distances from that location. The ground motion coming from a particular magnitude and distance is assigned an annual probability equal to the annual probability of occurrence of the causative magnitude and distance. The method assumes a reasonable future catalog of earthquakes, based upon historical earthquake locations and geological information on the recurrence rate of fault ruptures. To prepare these maps, the USGS analyzed all known seismic sources (surface faults, subduction zone and volcanic sources). Included in the computations are all historical and instrumental recordings of ground motions, gathered using a grid of 1-sq. km polygons.

The USGS has plans to put the Alaska ground motion hazard data on a CD with a latitude longitude look up. By entering a latitude-longitude coordinate pair, one will be able to see the probabilistic ground motion for any locale.

This ground motion hazard information is essential to creating and updating the seismic design provisions of building codes. Such information is used by insurance companies to set insurance rates for properties; engineers to estimate the stability and landslide potential of hillsides, and to design earthquake-resistant structures of different heights; and the EPA to set construction standards that help ensure the safety of waste-disposal facilities. At the time a site-specific project is proposed one will be able to call up the probabilistic ground motion values for that specific location.

All structures should be designed and built to meet or exceed the Uniform Building Code specifications for seismic zone 4 (highest earthquake hazard). These potential effects include ground motion amplification, soil liquefaction, and other earthquake induced ground failures. Design, construction, and operation of facilities must mitigate these effects with the goal of preventing loss of human life and significant environmental damage during earthquakes (Combellick et al., 1995:4). It is standard industry practice that facility siting, design, and construction be preceded by site-specific, high-resolution, shallow seismic surveys which reveal the location of potentially hazardous geologic faults. These surveys are required by the state prior to locating a drilling rig. Offshore drilling and production platforms are designed to meet the provisions of the American Petroleum Institute's (API) "Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms - Working Stress Design," API RP 2A-WSD, Twentieth (20th) Edition, July 1, 1993.

2. Volcanic Hazards

Alaska contains about 80 percent of all the active volcanoes in the United States and about 8 percent of the active volcanoes in the world. The western shore of Cook Inlet contains six volcanoes that have erupted in Holocene time (10,000 years ago). These are, from north to south, Mt. Spurr, Mt. Redoubt, Mt. Iliamna, Mt. Saint Augustine, and Mt. Douglas. Three of these (Mt. Spurr, Mt. Redoubt, and Mt. Saint Augustine) have erupted more than once this century and could well erupt again in the next few years or decades (Combellick et al., 1995:4).

Study of tephras (volcanic ash layers) in the Cook Inlet region indicates that eruptions have occurred every 1 to 200 years (Combellick et al., 1995, citing to Riehle, 1985). In the 20th century, these events have occurred every 10 to 35 years, and, for the last 500 years, tephras were deposited at least every 50 to 100 years, with Mt. Redoubt, Mt. Spurr, and Mt. Saint Augustine being the most active (Combellick et al., 1995:4, citing to Stihler, 1991; Stihler and others, 1992; Beget and Nye, 1994; Beget and others, 1994). Mt. Saint Augustine is one of the most active volcanoes in Alaska, with major eruptions in 1883, 1935, 1964, 1976, and 1986. Mt. Redoubt erupted in 1968 and 1989-90, and Mt. Spurr erupted in 1953 and 1992 (Combellick et al., 1995:4, citing to Wood and Kienle, 1990). No historic eruptions are known for Mt. Douglas or Mt. Iliamna, although geologic evidence shows that each has erupted during the past 10,000 years (Combellick et al, 1995:4).

During their periodic violent eruptions, the active glacier-clad stratovolcanoes produce abundant ash and voluminous mudflows that have threatened air traffic and onshore petroleum facilities (Combellick et al., 1995, citing to Riehle and others, 1981; Brantley, 1990). These are examples of the two major categories of volcanic hazards that will continue to threaten activities in the region. Proximal hazards are those close to volcanoes and consist of a wide variety of flow phenomena on the flanks of volcanoes or in drainages which head on the volcanoes (Combellick, 1995:5). Distal hazards are those farther from volcanoes, such as ashfall and tsunamis (Combellick et al, 1995:5).

A proximal hazard of particular concern to the sale area are floods generated by the rapid emplacement of large volumes of hot volcanic ejecta onto snow and ice on the upper flanks of volcanoes. All the volcanoes in Cook Inlet except Mt. Saint Augustine have permanent snow and ice stored in snowfields and glaciers on their upper flanks (Combellick et al, 1995:5).

The largest volcanically generated flood this century was caused by the January 2, 1990, eruption of Redoubt Volcano. The flood impacted the operation of the Drift River Oil Terminal (Combellick et al., 1995:5, citing to Brantley, 1990). The state allowed normal loading operations to resume once a protective dike was installed around the tank farm and support facilities to provide protection from flooding. This work was accomplished by August 1990 and the facility is fully operational. Another, and probably much smaller, flood came down the Chakachatna River in response to the 1953 eruption of Mt. Spurr. Floods caused by eruptions can impact any drainage on a volcano (Combellick et al., 1995:5).

In the area of the lease sale, drainages that could be impacted by volcanigenic floods are the Chakachatna River drainage (from Trading Bay to the McArthur River), Drift River drainage (from Montana Bill Creek to Little Jack Slough), Redoubt Creek, and the Crescent River. This is approximately half of the sale lands on the western shore of Cook Inlet. Drift River and Chakachatna River are the most likely to host floods.

A very large debris avalanche came down Redoubt Creek and formed the land that now underlies Harriet Point in latest Pleistocene time (1 million years ago), but that drainage does not appear to have had a large flow since that time (Combellick et al., 1995:5, citing to Beget and Nye, 1994). Large flows, some of which reached the present shoreline, came down Crescent River between about 3,600 and 1,800 years ago (Combellick et al., 1995:5, citing to Beget and Nye, 1994). The most probable volcanically induced floods are small, water-rich floods, which depending on the local hydrographic conditions, could impact roads, pipelines, and other infrastructure (Combellick et al., 1995:5).

Other proximal volcanic hazards on the western shore of Cook Inlet are lava flows, block-and-ash flows, pyroclastic[3] flows, and hot gas surges. The lands included in the lease area are far enough from the volcanoes that they are out of range of all but the very largest eruptions (eruptions on the scale of the 1980 Mount St. Helens or 1991 Mt. Pinatubo eruption). Eruptions this large are rare, although they are certainly possible and have happened at several of the Cook Inlet volcanoes, the most recent being the eruption of Mt. Katmai in 1912.

The most common distal hazard is ashfall, where volcanic ash (finely ground volcanic rock) is lofted into the atmosphere and stratosphere by explosive eruptions, drifts downwind, and falls to the ground. There have been dozens of such events from Cook Inlet volcanoes in this century. In most cases, volcano ashfalls have been a few millimeters or less in thickness. The primary hazard of such ashfalls is damage to mechanical and electronic equipment such as engines, which ingest ash past the air filter, computers, and transformers, possibly causing electrical shorts. Ashfalls of a few millimeters should be expected throughout the Cook Inlet and Susitna basins with a long-term average frequency of a few every decade or two. Ashfalls thick enough to collapse buildings are possible but rare (Combellick et al., 1995:5).

3. Tsunamis

Tsunamis (large water waves induced by earthquakes, subsea landslides, or volcanic activity) are a potential hazard for lower Cook Inlet (south of the Forelands). The most likely cause of a tsunami in Cook Inlet is either a large magnitude earthquake similar to the 1964 quake or a violent eruption of Mt. Saint Augustine. Tsunamis are generated when large volumes of sea water are displaced, either by tectonic displacement of the sea floor or by large rockfalls or landslides. The narrow, elongate geometry of Cook Inlet should reduce the chances that a tsunami generated outside the inlet will propagate significant destructive energy into it. For example, the tsunami generated by the 1964 earthquake produced damage in the lower Cook Inlet at Rocky Bay and Seldovia, and hit much of the west coast of the lower inlet, but caused no damage in upper Cook Inlet. Conversely, if a tsunami were caused by a displacement of the sea floor in Cook Inlet, it probably would have little effect in open waters but could produce significant damage along the coastline (Meyer, 1993 citing to Hampton).

Marine portions of the sale area are relatively shallow and protected from open ocean, therefore the hazard from distant tsunamis is low. The hazard from local earthquake generated tsunamis is also low because there are no known active surface faults in the inlet, no adjacent steep slopes to serve as sources of massive slides into the inlet, and no evidence of thick, unstable seafloor deposits that would fail in massive underwater slides. There is no known geologic evidence of prehistoric tsunamis in this area (Combellick et al., 1995:4).

A major current concern in Cook Inlet today is the possibility of tsunamis being generated by volcanic activity on Mt. Saint Augustine. A volcanic eruption can produce debris avalanches with velocities of up to 328 feet per second. When the avalanche reaches the sea, the displaced water mass can become a tsunami. These waves would hit both the east and west shores of Cook Inlet. While the west shore is largely unpopulated, populated areas on the east shore within lower Cook Inlet could be subject to extensive damage. These include Port Graham, Anchor Point, Nanwalek, Seldovia, Homer and several small communities (Meyer, 1993 citing to Kienle, Kowalik and Murty, 1987). Mt. Saint Augustine volcano presents the greatest threat to shoreline and offshore structures because of its island location in southwestern Cook Inlet. Mt. Saint Augustine experiences frequent violent eruptions, and has a propensity for producing unstable summit domes that periodically collapse into large, rapidly moving debris avalanches. These enter Cook Inlet and generate rapidly spreading tsunamis (Reger, 1993 citing to Begét and Kienle, 1992). Other major volcanoes in the Cook Inlet region, including Mt. Iliamna, Mt. Redoubt and Mt. Spurr, are located farther inland, and are not considered likely to produce similar submarine debris flows and corresponding tsunamis.

[3] Volcanic material that has been explosively ejected from a vent.

The volcanigenic tsunami hazard in Cook Inlet is presently poorly understood, although the potential for the generation of large waves is real. There is some anecdotal evidence in historic records that the 1883 eruption of Augustine generated a wave that was several meters high when it impacted Nanwalek, on the east side of Cook Inlet (Combellick et al., 1995:6, citing to Beget and Kienle, 1992). There are also historical documents that discount the existence of this. In any event, geologic evidence of repeated anomalous waves has not been found (Combellick et al., 1995:6, citing to Waythomas, 1995).

4. Marine and Seafloor Hazards

Cook Inlet has a maximum tidal range of 4 to 11 m, depending on location, which produces rapid tidal flows and strong riptides (Combellick et al., 1995, citing to Evans and others, 1972; Hayes and others, 1976; National Oceanic and Atmospheric Administration, 1977). High tidal-current velocities in upper Cook Inlet prevent deposition of clay and silt-size sediments, which largely remain in suspension. Bottom sediments in the sale area are mainly gravel and sandy gravel with gravel content of 50-100 percent (Combellick et al., 1995, citing to Sharma and Burrell, 1970). Similar deposits in lower Cook Inlet are thought to be reworked and redistributed coarse-grained glacial material (Combellick et al., 1995, citing to Rappeport, 1981). These deposits show no evidence of gravitationally unstable slopes or soft, unconsolidated sediment (Combellick et al., 1995, citing to Minerals Management Service, 1995).

Several pipeline failures in upper Cook Inlet have been directly attributed to the current-sediment interaction. (See the Oil Spill section in this chapter for discussion of pipeline failure.) As the bottom sediments shift under the influence of bottom currents, sections of the pipeline are undermined and become unsupported. The pipeline may then flutter, which causes fatigue and failure. Actions taken in Cook Inlet to prevent this situation include conducting annual side-scan sonar surveys, attaching pipelines to piles driven into the seafloor, placing large bags of a sand-cement mixture around the pipelines to anchor them, and using heavy walled pipe (Meyer, 1993 citing to Whitney and others, 1979).

During the winter months, ice forms up to three feet thick on upper Cook Inlet. This ice, propelled by the swift tidal currents, creates very large load stresses on the offshore platforms. Since the platforms are designed to withstand the ice loads, this should not present a problem. Ice is not as severe a problem in the southern part of the inlet due to a higher salinity, less fresh water inflow, and a greater proportion of warm ocean waters.

Winter ice conditions combined with tidal action may occasionally hinder offshore operations in the upper inlet from December through April (Combellick et al., 1995, citing to Sharma and Burrell, 1970). During the winter of 1970-71, inlet ice extended as far south as Anchor Point and Cape Douglas. Although blocks of floe ice generally reach a thickness of 1.2 m in Cook Inlet, grounding of these blocks forms large piles of ice blocks (stamukhi) that exceed 12 m in thickness and, where floated, stamukhi have damaged ships in the inlet (Combellick et al., 1995, citing to Evans and others, 1972). Numerous large erratic blocks in shallow, nearshore waters are hazards to ship navigation.

5. Flood Hazards

In addition to volcanigenic flooding on the west side of Cook Inlet, flood hazards in the Cook Inlet area result in decreasing order of frequency, from ice jams, glacial outburst (jökulhlaups), and high rainfall.

Ice jam flooding occurs during breakup when ice blocks a river or stream, in effect becoming a dam. This causes water to back up and flood the adjacent land. Ice jam flooding is localized, but affects the greatest number of residents over time because of the high population concentration along rivers (Combellick et al., 1995:7, citing to J. M. Dorava, U.S. Geological Survey, personal communication, 1995).

Glacial outburst occurs when glacial movement opens a pathway for water trapped behind a glacier to escape. Rivers are subject to large magnitude outburst floods as a result of the sudden drainage of large, glacier-dammed lakes, particularly on the west side of Cook Inlet. Major streams affected by outburst floods include Beluga River, Chakachatna River, Middle River, McArthur River, Big River, and Drift River (Combellick et al., 1995, citing to Post and Mayo; 1971). For example, in September 1982, over 95 percent of Strandline Lake drained, releasing about 700 million cubic meters (185 billion gallons) of water. Strandline Lake has drained catastrophically into Beluga River every 1 to 5 years since about 1954. (Combellick et al., 1995:7, citing to Sturm and Benson, 1988). The most reliable predictor of outburst floods from Strandline Lake is the development of a calving embayment in the lobe of Triumvirate Glacier, which dams the lake (Combellick et al., 1995:7).

On the east side of Cook Inlet, in the Kenai Lowlands, high-water levels in the Kenai River frequently occur due to the sudden drainage of glacier-impounded lakes at the head of the Snow River tributary east of Kenai Lake and lakes held in by Skilak Glacier. Several small lakes impounded by Tustumena Glacier are potential sources of unexpected floods in Kasilof River. In October 1995, Skilak Glacier released an outburst flood that resulted in water levels cresting about 0.5 m below flood stage at Kenai Keys and Soldotna (Combellick et al., 1995, citing to unpublished data, National Weather Service, October 1995). This outburst flood had a total volume considerably less than previous events in 1985 and 1990; no damage was reported from the 1995 event. However, future outbursts from a Skilak glacier dammed lake could result in extensive lowland flooding, as occurred in 1969 when severe damage resulted in Soldotna (Combellick et al., 1995, citing to Post and Mayo, 1971). Signs of impending outburst releases are high lake water levels, abundant calving into the lake, and water present on northern margins of the glacier, including small marginal lakes (Combellick et al., 1995:7, citing to unpublished data, National Weather Service, October 1995).

The least frequent cause of flooding in the Cook Inlet area is excessive rainfall. This results from unusual combinations of extreme meteorological conditions. Recent heavy flooding in September 1995 resulted from (1) interaction of tropical moisture and a deep low pressure center in the north Pacific Ocean, (2) blockage of the eastward movement of this low by a high-pressure ridge in eastern Alaska and western Canada, (3) saturated soil conditions, and (4) greater than normal glacial melt due to preceding storms. Excess sediment deposition in channels due to rapid runoff decreased the carrying capacity of the streams. As a result, the lower Kenai River remained above flood stage for over 10 days. Crest water levels were 1.1 m above flood stage at Kenai Keys and 0.76 m above flood stage at Soldotna (Combellick et al., 1995, citing to unpublished data, National Weather Service, October 1995). An analysis of this flood indicates that it represents a 100-year event at Soldotna (Dorava, 1998).

The primary hazards to facilities from river flooding are high water levels, bank erosion, deposition at the river mouth, high bedload transport, and channel modification (Combellick, 1995:7).

Seasonal flooding of lowlands and river channels is extensive along major rivers that drain into Cook Inlet. Thus, measures must be taken prior to facility construction and field development to prevent losses and environmental damage. Pre-development planning should include hydrologic and hydraulic surveys of spring break-up activity as well as flood-frequency analyses. Data should be collected on water levels, ice floe direction and thickness, discharge volume and velocity, and suspended and bedload sediment measurements for analysis. Also, historical flooding observations should be incorporated into a geophysical hazard risk assessment. All inactive channels of a river must be analyzed for their potential for reflooding. Containment dikes and berms may be necessary to reduce the risk of flood waters that may undermine facility integrity.

Coastal Erosion

Coastal erosion and deposition is another potential threat to development located on or near the coastline. Frequent storms accompanied by strong winds result in strong wave action that erodes shorelines composed of unconsolidated sediments and weakly cemented Tertiary sedimentary rocks (Combellick et al., 1995:6, citing to Hayes and Michel, 1982). The coastal bluffs around the inlet range from 20 to 200 feet in height, and are currently receding in response to natural processes such as wave action, precipitation, and wind (Meyer, 1993 citing to KPB, 1990). Development, such as roads and gravel excavation in the coastal areas, also has a destabilizing effect on the coastal bluffs and further contributes to erosion as well as subsidence and ground failure related to earthquakes.

Erosion rates, sediment grain size and cohesiveness, riverbank stability, and nearshore bathymetry must all be considered in determining facility siting, design, construction, and operation. They must also be considered in determining the optimum oil and gas transportation mode. Structural failure can be avoided by proper facility set-backs from coasts and river banks. Mitigation measure 6 prohibits the siting of permanent facilities, other than road and pipeline crossings, within one-half mile of the banks of major rivers. Docks and road or pipeline crossings can be fortified with concrete armor, and the placing of retainer blocks and concrete-filled bags in areas subject to high erosion rates.

6. Shallow Gas Deposits

Shallow gas deposits have been encountered in the Cook Inlet area and pose risks similar to overpressured sediments. The Steelhead and Grayling platforms have experienced blowouts due to shallow gas. These incidences are described in the oil spill history and risk discussion later in this chapter. The same mechanisms for blow-out prevention and well control are employed to reduce the danger of loss of life or damage to the environment.

7. Summary

There are a number of geophysical hazards that pose potential problems to future installations both onshore and offshore. However, oil and gas exploration, development, and production activities have been conducted safely in the area for over thirty years. The risks from earthquake damage can be minimized by siting onshore facilities away from potentially active faults and unstable areas, and by designing them to meet or exceed Uniform Building Code specifications for seismic zone 4 (highest earthquake hazard). The zone 4 specifications apply as minimums at all locations in the area (Meyer, 1993). Offshore platforms need to be designed according to API recommendations. Additional precautions should be taken to identify and accommodate site-specific conditions such as unstable ground, flooding, and other localized hazards. Proper siting and engineering will minimize the detrimental effects of these natural processes (Combellick et al., 1995:8).

B. Likely Methods of Oil and Gas Transportation

The Cook Inlet basin has produced crude oil and natural gas since the 1960s. As a result, the area has a well-developed infrastructure for transporting petroleum. In the past nearly 80 percent of the crude oil produced in Cook Inlet was sold to U.S. markets on the West Coast. The remaining 20 percent was co-mingled with North Slope crude and refined by Tesoro Alaska Petroleum Company (Necessary, 1993). Currently, however, all Cook Inlet crude oil is refined in the Tesoro refinery at Nikiski.

The oil and gas transportation system in the Cook Inlet region consists of the following major components: 1) offshore and onshore pipelines; 2) marine terminals with offshore loading platforms; and 3) tank vessels. Oil and gas produced in the Cook Inlet region are transported by a combination of these elements as discussed in this section. The existing system or portions of it will most likely be used to transport oil from the Cook Inlet area if any is discovered.

A discussion of specific transportation alternatives for oil from the Cook Inlet area is not possible at this time because strategies used to transport potential petroleum resources depend on many factors, most of which are unique to an individual discovery. The location and nature of oil or gas deposits determine the type and extent of facilities necessary to develop and transport the resource. No oil or gas may be transported from leases until the operator has obtained the necessary permits and authorizations from federal, state, and local governments. ADNR and other state, federal, and local agencies will review the specific transportation system when it is actually proposed. However, a general discussion is warranted and the following are the components that might be in any transportation system. See Figure 6.5 in Chapter Six for a map of the existing oil and gas infrastructure in Cook Inlet.

1. Pipelines

Offshore and onshore pipelines have operated in the Cook Inlet region since the 1960s. Existing infrastructure includes five onshore and fourteen offshore crude oil pipelines systems with a total of about 156 miles of pipe. About 84 miles of pipeline transport crude oil from offshore platforms to shore. After processing, the oil is further transported through two onshore pipelines to the Nikiski marine terminal on the east side of the Inlet or to the Drift River marine terminal on the west side. (Belmar Management Services, 1993)

Although some new pipelines may be necessary if oil or natural gas is discovered on leases away from existing facilities, much of the existing infrastructure could be used to transport any new oil or gas to existing terminals or processing facilities. The impacts of possible production from these leases will be much less than if the region were undeveloped and new pipelines, production facilities, and other transportation systems had to be built. If new natural gas reserves are discovered near communities, the gas could be made available to those communities through new pipelines if the communities desire it and if economic factors favor the project.

a. Onshore Crude Oil Pipelines

The onshore Swanson River field pipeline was installed in 1960 following the discovery of the field, and it transports crude oil to the Nikiski marine terminal. A short onshore pipeline, less than a mile long, transports Cook Inlet crude oil produced from the east side of the basin and North Slope crude oil brought in by tanker from the Nikiski marine terminal to the Tesoro Refinery.

Onshore pipelines in the Cook Inlet region are normally buried and the ground reseeded, so they do not pose an obstacle to wildlife or result in scenic degradation. Buried pipelines are more expensive to install and to maintain than unburied pipelines, but they have a longer life. Spills may result from pipeline leaks in either buried or unburied pipelines, and leak detection systems play a primary role in reducing discharges of oil from either system. The risk of spills from onshore pipelines is considerably lower than the risk from tankers. (Samuels, Hopkins, and Lanfear 1981:14) For a discussion of leak detection methods, please see the section on oil spills later in this chapter.

b. Offshore Crude Oil Pipelines

An offshore pipeline moves oil from the Middle Ground Shoal field, located in the middle of the Inlet, to the Nikiski marine terminal on the east side of Cook Inlet. The Cook Inlet Pipe Line Company transports crude oil via an offshore pipeline system from the Trading Bay, McArthur River, and Granite Point fields to the Drift River marine terminal on the west side of the Inlet. (Belmar Management Services, 1993)

Offshore pipelines do not hinder water circulation and minimally affect fish and wildlife habitat. Weighted pipelines are used in Cook Inlet because tidal currents are exceptionally strong. These pipelines are normally buried in trenches in shallower waters to avoid creating a navigational hazard or being damaged by a ship's anchor or by sea ice or catch in a fishing net. In deeper water, the weighted pipelines may become silted-in or self-buried. Subsea pipelines are the most likely system for transporting oil or gas from new offshore development areas to a loading or processing facilities. Pipelines have transported petroleum liquids under Cook Inlet waters since the 1960s and have demonstrated their durability. The risk of spills from subsea pipelines is considerably less than for tankers (Anderson, 1992). Subsea pipelines are expensive to build and maintain. They can be difficult to monitor for leaks, defects, and corrosion problems, however significant advances have been made in recent years. For a discussion of leak detection methods, please see the section on oil spills below.

c. Natural Gas Pipelines

Natural gas produced in the Inlet moves via offshore and onshore pipelines to the Phillips/Marathon LNG facility and the Union Chemical Plant and to Kenai and Anchorage for commercial and residential use. Natural gas also powers the Chugach power plant at Beluga and supplies fuel for homes in the Mat-Su area. (Phillips/Marathon, p. 5)

Gas pipelines use compressors to push natural gas through the lines after the gas has been treated. Separators isolate the components. Heaters prevent hydrate formation within the equipment. Dehydrators remove almost all of the water vapor. The piped gas is measured and monitored by a computer system that coordinates the operation of valves, prime movers and conditioning equipment. If a problem occurs, the computer initiates corrective actions and sounds alarms at the appropriate control points. Released gas would probably dissipate unless a spark sets it off. Ignition could result in a violent explosion. (University of Texas, 1986, pp. 297-301)

Enstar adds an odorant such as mercaptan to natural gas that will be used as fuel in homes or business facilities. The human nose can detect a one percent concentration of gas. This is far below dangerous levels. Gas sent to petrochemical or LNG plants is not odorized since the chemical could interfere with processing. (University of Texas, 1986, pp. 297-301)

2. Marine Terminals

The marine crude oil terminals in Cook Inlet include storage facilities and offshore loading platforms. The Nikiski complex has been in operation since 1963 and includes the Phillip/Marathon liquefied natural gas (LNG) plant, Tesoro's refinery and Union Chemical's ammonia-urea plant. The complex receives, stores and pumps crude oil to the Tesoro refinery. The Drift River marine terminal started operating in 1967. It receives Cook Inlet crude oil via pipeline from production areas on the west side of the Inlet and stores the oil until tankers move it across the Inlet to the Tesoro refinery. Currently, no Cook Inlet crude oil is shipped out of the state.

Crude oil terminal facilities generally store quantities of oil equivalent to several large tanker loads. Therefore, the possibility for a very large spill exists at these facilities. A strong earthquake or extensive natural disaster could damage the facilities and initiate a large spill. The risk of explosion or sabotage at the facilities also exists. Accidental ballast discharge or loading or unloading accidents could also cause a spill. However, environmental risks have been minimized through improved design, construction, operating techniques and other prevention measures. For information on oil spill risk and prevention, please see the discussion on oil spills.

The Kenai Liquefaction Plant includes facilities for liquefying, storing and loading natural gas. The gas is liquefied by lowering its temperature to -259 °. During this process the gas shrinks to 1/600th of its original volume. The LNG is stored in three heavily insulated, 225,000-bbl storage tanks. While in storage some of the liquefied gas “boils off.” This maintains the remaining LNG at its liquid temperature and provides fuel for the plant’s large refrigeration units. (Phillips/Marathon, pp. 7-11)

3. Tankers

Tanker traffic in the Inlet currently carries oil produced from the west side of the Inlet to the east side to be refined and delivers refined petroleum products from the Nikiski complex to other parts of Alaska or the Pacific Rim. The Tesoro refinery buys west side crude at the Drift River terminal and tankers it across the Inlet about every ten days. (Meitner, 1998 and Lentsch, 1998)

A total of 527 tanker visits to the Drift River facility between 1980 and 1992 moved over 192 million barrels of Cook Inlet crude oil. From 1985 through 1991, a total of 806 vessel loadings delivered over 132 million barrels of North Slope crude oil to the Chevron and Tesoro refineries at Nikiski. Chevron closed its refinery in July 1991. In 1992, the Tesoro refinery took delivery of nearly 17.5 million barrels of North Slope oil from 69 vessel loadings (Jackson, 1993). Tesoro Alaska Petroleum Company recently announced that it will no longer process North Slope crude oil at its Cook Inlet refinery. The company will refine Cook Inlet crude and bring in refined product or partially refined crude from its recently acquired refineries in Washington and Hawaii. Tesoro has also experimented with small shipments of Russian crude and might start importing more foreign oil. (ADN, 1998)

Two specially designed tankers each transport about 555,000 bbls of LNG to Japan where the gas converts back to its gaseous state as it enters the natural gas pipelines. The ships load in about 18 hours and make 16 to 19 trips per year. The trips average 20 days and cover a round-trip distance of about 6,600 nautical miles. (Phillips/Marathon, pp. 12-14)

Union Chemical barges urea fertilizer, which is manufactured from natural gas, to markets out of the state. The price has fallen dramatically, and the company may lay off 21 employees in the near future. (Lentsch, 1998)

Tankers must travel through the Inlet at least five miles offshore to allow enough maneuvering room. They pick up or drop off a marine pilot and sometimes use a deep-water anchorage area in Kachemak Bay to accommodate scheduling conflicts or weather problems. Only three vessels may use the anchorage area at one time (MMS, 1995). Vessels pass through the middle of Kennedy Entrance and stay beyond state waters off of Kodiak Island. (Meitner, 1996)

Due to the swift currents and tides in the Inlet, tankers routinely execute a rather unconventional docking maneuver at Drift River and Nikiski. The marine pilot places the bow of the ship into the current, adjusts the engines to stem the tide and drops anchor to allow the generation of higher RPMs on the engines to get better rudder control. The pilot uses the force of the current to set toward or away from the dock by putting the ship at an angle to the axis of the current. The forces of the ship at the dock must equal the forces of the current. One, and sometimes both, anchors must be dragged to slow the ship’s speed to equal the speed of the current. The engines are not stopped nor anchors weighed until the vessel has enough mooring lines on the dock to equal the force of the current. (O’Hara, 1998)

C. Oil Spill Risk, Prevention and Response

1. Oil Spill History and Risk

Any time crude oil or petroleum products are handled, there is a risk that a spill might occur. Oil spills associated with the exploration, development, production, storage and transportation of crude oil may occur from well blowouts or pipeline or tanker accidents. Petroleum activities may also generate chronic low volume spills involving fuels and other petroleum products associated with normal operation of drilling rigs, vessels and other facilities for gathering, processing, loading, and storing of crude oil. Spills may also be associated with the transportation of refined products to provide fuel for generators, marine vessels and other vehicles used in exploration and development activities.

The AOGCC compiled statistics for all types of offshore petroleum spills in the Cook Inlet region for the period 1965 to 1980. During this period, 187 recorded spills occurred that were associated with the production and transportation of crude oil resulting in a total of 7,596 bbl (319,032 gal) of petroleum spilled. These records also show that there were 206 non-industry spills (e.g. fishing vessels, product transportation vessels, and other vessels not related to the oil and gas industry spills). These spills totaled 22,746 bbl (955,332 gal). (AOGCC 1981:1-2)

The 1997 "Cook Inlet Sub-Area Contingency Plan" lists significant petroleum and hazardous substances spills in the Inlet and on land from July 1987 to January 1997. Cook Inlet crude oil spilled in the inlet during this time totaled about 219,410 gallons. The *Glacier Bay* spill in 1987 constitutes 210, 000 gallons of this total. Crude oil spilled on land totaled 2,000 barrels. The reader is referred to the subarea contingency plan for a full description of the inland and navigable waters spill history. (ADEC, 1997a: E-14 - 18)

Exploration and Production: Spills related to petroleum exploration and production must be distinguished from those related to transportation because the operations have different risk factors and spill histories. Exploration and production facilities include offshore platforms, drill rigs, pipelines, and facilities for gathering, processing, storage, and loading of oil. These facilities are discussed below. When spills occur at these facilities, they are usually related to everyday operations such as fuel transfers.

Cook Inlet Platform spills total approximately 250 barrels (10,500 gallons) in the period from 1984 to 1994. In November 1988 Spark Platform released about 20 barrels (840 gallons). Platform Anna spilled about 110 barrels (4,620 gallons) in January 1990 and 15 barrels (630 gallons) in November 1994. In April 1992, King Salmon platform discharged 9 barrels (375 gallons) and in April 1994, the Baker platform spilled 96 barrels (4,030 gallons).

The most dramatic form of spill can occur during a well blowout which occurs when high pressure gas is encountered in the well and sufficient precautions, such as increasing the weight of the drilling mud have not been taken (Williams and Meyers, 1981). The result is that oil, gas, or mud is suddenly and violently expelled from the well bore, followed by uncontrolled flow from the well. Blowout preventers which immediately close off the open well and prevent or minimize any discharges, are required for all drilling and work-over rigs, and are inspected routinely by the AOGCC.

A blowout that results in an oil spill is extremely rare and none are known to have occurred in Alaska. However, natural gas blowouts have occurred. The Pan American blowout occurred offshore in August 1962 when the well, Cook Inlet State No. 1, was being drilled from a barge located eight miles east and two north of North Forelands. The well encountered natural gas and blew gas from August 23, 1962 to October 23, 1963. Pan American Petroleum Corporation drilled a relief well, No. 1-A, to stop the blowout.

The Grayling Platform experienced a short-term natural gas blowout in May 1985. Union Oil Company was drilling well G-10RD into the McArthur River Field when the blowout occurred. The event lasted from May 23 to May 26. The platform was evacuated, and observers noted a plume of gas, water and mud reaching a height of 600 feet above sea level. Union prepared to drill a relief well, but the blowout stopped on its own because of bridging. Bridging seals off the escaping fluids and gases when part of the formation around the well bore collapses into the well bore and naturally closes it. The operator regained permanent well control by pumping cement through the drill pipe in G-10RD. There was no fire nor injuries, and personnel shut-in all oil wells prior to evacuating the platform.

The last reported blowout in Cook Inlet occurred when the Steelhead Platform well, M-26, encountered natural gas in December 1987. Marathon Oil Company was drilling into the McArthur River Field. The gas blowout lasted from December 1987 until June 1988. A relief well was started but the blowout bridged before the relief well was completed. The well blew out natural gas, water, coal, and rocks. The escaping gas caught fire which damaged the deck of the platform, and some injuries occurred as workers attempted to stop the blowout.

A worst case discharge from an exploration or production facility is restricted by the maximum storage capacity of the facility or vessel or by a well's ability to produce oil. For example, a well with a production rate of 2,500 bbl per day can only spill a maximum of 2,500 bbl per day. There never has been a major oil spill (1,000 bbl or greater) from activities associated with the exploration, development, or production facilities in Cook Inlet.

Pipelines: Cook Inlet has approximately 156 miles of onshore and offshore oil pipeline associated with current oil development. Pipe sizes range from six to ten inches in diameter. Pipelines are discussed in the Transportation section above. Although most of the existing pipelines are at least 25 years old, they show little internal and external corrosion. The 1993 Belmar report prepared for ADEC finds that the pipelines are "fit-for-purpose" and that the risk for a significant spill is low (Belmar Management Services, 1993:1).

The fact that the pipelines have reached their original design life does not imply that the lines have become inadequate or unsafe. The integrity of an older pipeline is a function of how well the line has been maintained, the type of throughput, and how the current operating conditions compare with the original design conditions. With proper maintenance, the life of a pipeline can be several multiples of the original design life (Belmar Management Services, 1993).

A 14-inch pipeline can store about 1,000 bbl per mile of pipeline length. Under static conditions, if oil were lost from a five-mile stretch of this pipeline (a hypothetical distance between emergency block valves), a maximum of 5,000 bbl of oil could be discharged if the entire volume of oil in the segment drained from pipeline.

Some pipeline failures have occurred on the offshore pipelines. Failures have been caused by (1) current-induced vibration, (2) external corrosion at risers where the pipeline enters the platform, (3) pipeline rubbing, (4) ice scour, and (5) minor flange leaks. The first failure due to current induced vibration happened almost immediately after the installation of dual 8-inch lines from Shell Platform A to shore in 1965. The initial failures were on the two inadequately supported risers at the platform. Later failures occurred in areas of unstable bottom in 1966, 1967, 1968 and 1976. There have not been any reported pipeline failures in these lines since 1976. The oil and gas 10-inch Granite Point field pipelines crossing the Inlet from platform Anna to the Kenai Pipe Line system experienced nine failures until 1974. Amoco installed twin 6-inch pipelines to connect platforms Anna and Bruce to the Cook Inlet Pipe Line Company's pipeline on the west side of the Inlet, and the original line was abandoned in 1982 or 1983 (Belmar Management Services, 1993).

Marine Terminals: Both the Nikiski and Drift River terminal facilities generally have good safety records. Volcanic activity associated with Mt. Redoubt in 1989 and 1990 caused the temporary closure of the Drift River facility between January and mid-June 1990 due to the threat of flooding. By August 1990, following construction of new protective dikes, the terminal resumed normal operations.

In March of 1990, approximately 2,300 bbl (96,600 gal) were spilled at Drift River when a valve on tank number 3 was accidentally left open. The entire spill was contained within protective dikes and none was released into the water. Nearly all of the spilled oil was cleaned up by returning it to the storage tank or by direct treatment. In December 1990, another incident occurred when ice carried by swift currents forced the UNOCAL tanker *Coast Range* away from the dock at the Drift River facility. This caused a spill of approximately 15 bbl (630 gal) of oil located in the pipes between the dock and the ship. Cleanup workers used absorbents to clean up the spill because booms and skimmers were ineffective in the heavy ice (ADN, 1990:B-1). ADEC estimates that 30 percent of the spill was cleaned up and 10 to 20 percent evaporated. This left approximately 7.5 bbl (315 gal) unrecovered.

On December 5, 1995, a spill occurred at the Tesoro tank farm in Nikiski. Crude oil overflowed when a high-fill-level alarm failed during a tank-to-tank transfer. Some of the oil escaped the secondary containment berm around the tank and reached Cook Inlet. The oil moved north in the water and into the rip currents. CISPRI responded and recovered some of the oil. The remainder disappeared within three days (ADEC, 1995). Approximately 2,500 to 2,900 gallons of crude oil were released, and DEC fined Tesoro (Lentsch, 1998).

Tanker Vessels: Worldwide statistics (excluding the Russian Federation) confirm that tankers, rather than exploration and production activities, present the greatest potential for large-scale oil pollution. Throughout the 1980's there has been a fairly constant rate of 1.3 spills per billion barrels of oil transported (Anderson, 1992). Spill rates for single hull tankers are considerably higher than for pipelines. A tanker accident can result in the release of large quantities of oil in a short time, causing severe environmental damage. An oil spill in a marine water setting is also much more difficult to contain than one on land, since ocean currents and tidal actions carry the oil over a much larger area. In the late 1960s, for example, two tanker incidents each spilled approximately 1,000 bbl (MMS, 1985:IV-A-9-11). Marine tankers have operated in Cook Inlet for over 50 years and for the most part, have operated safely. However, charted and uncharted navigational hazards do pose risks for tankers in the waters of Cook Inlet.

Winter ice is one hazard that all marine traffic must contend with in Cook Inlet. A number of ships over the years have suffered power failures in the Inlet due to engine overheating when ice is sucked into the vessel's sea chest, a device that provides water to the engine for cooling purposes. When ice blocks the cooling water and the engine overheats, engineers may manually shut it down or the engine may automatically shut down. This leaves the ship dead in the water. This problem has virtually been eliminated since the Coast Guard developed and began enforcing its Winter Ice Rules (USCG, 1998). The rules are regulations that the Coast Guard implements during the winter season in Cook Inlet. The Coast Guard require in-bound ships to anchor near Homer and submit to an inspection to ensure they comply with the Ice Rules. Among other requirements, the rules include ensuring that the crew are properly outfitted and all equipment is properly prepared for the winter climate and keeping the ice chest sufficiently submerged to avoid taking in ice. Experienced pilots, accurate weather and ice observations, Coast Guard inspections, changing navigation routes based on ice conditions, and timing transits with tides have lead to many years of successful navigation of the Cook Inlet by many kinds of marine vessels (UAA, 1998).

During the summer of 1987, the tanker *Glacier Bay* spilled between 2,350 and 3,800 bbl of North Slope crude oil being transported into Cook Inlet for processing at the Nikiski Refinery (ADEC, 1988:1). Less than ten percent of the oil was recovered, and the spill interrupted commercial fishing activities in the vicinity of Kalgin Island during the peak of the red salmon run. Although not on the scale of the *Exxon Valdez* spill, this spill focused attention on oil spill response and cleanup capabilities in Cook Inlet which are discussed below.

Another example of the potential magnitude of a tanker spill is the March 1989 *Exxon Valdez* oil spill, the largest recorded spill in US waters (nearly 261,900 bbl). Oil from the *Exxon Valdez* contaminated fishing gear, fish, and shellfish, killed numerous marine birds and mammals, and led to the closure or disruption of many Prince William Sound, Cook Inlet, Kodiak, and Chignik fisheries (Alaska Office of the Governor 1989

"Exxon Valdez Oil Spill Information Packet"). Effects of the oil spill on fish and other wildlife can be found in the section entitled "Cumulative Effects."

The spills from the *Glacier Bay* and the *Exxon Valdez* were not effectively contained, and the effectiveness of the cleanup efforts remains the subject of controversy. In the case of the *Glacier Bay* spill in Cook Inlet, tidal currents and confusion concerning who would respond to the spill caused problems. In the *Exxon Valdez* oil spill in Prince William Sound, the sheer size of the spill quickly overtaxed available cleanup resources at a time when response plans had been allowed to languish.

Both incidents demonstrated that preventing catastrophic tanker spills is easier than cleaning them up and focused public, agency, and legislative attention on the prevention and clean up of oil spills. Numerous changes were effected on both the federal and state levels. At the state level, new statutes created the oil and hazardous substance spill response fund (AS 46.08.010), established the Spill Preparedness and Response (SPAR) Division of ADEC, (AS 46.08.100), and increased financial responsibility requirements for tankers or barges carrying crude oil up to a maximum of $100 million (AS 46.04.040(c)(1)). The discussion of regulations and laws regarding oil spills is presented later in this section.

On January 6, 1999 a recreational snowmachine driver discovered that an eight-inch crude oil pipeline buried forty inches below the surface was leaking in the Swanson River Oil Field in the Kenai National Wildlife Refuge. The responsible party, Unocal, estimates that 60 barrels (2520 gallons) of crude oil and 1300 barrels (54,600 gallons) of produced water was spilled based on one day's production output from Tank Setting I-27. The suspected cause of the breach is corrosion of the buried pipeline. The pipeline is at least 30 years old.

The spill took place on federal land. The area of contamination along the pipeline right-of-way is estimated to be about 250 ft. in length and 171 ft. in width. Cleanup consisted of removing contaminated snow and transported it to Unocal's solid waste facility, which is permitted and lined. Resources at risk are minimal. There have been no sightings of wildlife in the area. The only disturbance has been to vegetation due to cleanup actions. As of January 13, 1999 the cause of the spill is unknown. Unocal will begin repairs to the pipeline after the surface contamination is removed (ADEC, 1999).

2. Oil Spill Prevention

A number of measures contribute to the prevention of oil spills during the exploration, development, production, and transportation of crude oil. Some of these are presented as mitigation measures in Chapter Nine, and some are discussed at the beginning of this section. Prevention measures are described in oil discharge prevention and contingency plans prepared by the industry. Proper training and routine surveillance are important components of oil spill prevention.

Prevention measures used during exploration include:

- Use of existing facilities and roads.
- Waterbody protection, including proper location of onshore oil storage and fuel transfer areas.
- Use of proper fuel transfer procedures.
- Use of secondary containment, such as impermeable liners and dikes.
- Proper management of oils, waste oils, and other hazardous materials to prevent ingestion by bears and other wildlife.

Should development occur, additional measures include:

- Consolidate facilities.
- Place facilities away from fishbearing streams and critical habitats.
- Locate pipelines to facilitate spilled oil containment and cleanup.
- Install pipeline leak detection and shutoff devices.

Pipelines. Leak detection systems will play a primary role in preventing discharges of oil from any pipeline, which might be constructed in the sale area. Once a leak is detected, valves at both ends of the pipeline, as well as intermediate block valves, can be manually or remotely closed to limit the amount of discharge. The number and spacing of the block valves along the pipeline will depend on the size of the pipeline and the expected throughput rate (Nessim and Jordan, 1986:68).

The technology for monitoring offshore pipelines is continually improving. The Cook Inlet Pipe Line Company and the Kenai Pipe Line Company currently use the volume balance method (comparing input volume to output volume) (Belmar Management Services, 1993). The Kenai Pipe Line Company uses the following leak prevention and detection methods:

1. hydrostatic testing annually.
2. monitor output and input continually.
3. pressure monitors on pumps record pressure changes and shut down automatically if there is a significant change.
4. once a week shut down the system to pressure up the system against a closed valve and let sit for 24 hours (Amen, 1996).

Leak detection methods being researched in the lower 48 and not currently used in the Cook Inlet area include acoustic monitoring, pressure point analysis, and combinations of some or all of the different methods (Yoon and Mensik, 1988). The approximate location of a leak can be determined from the sensors along the pipeline. A computer network is used to monitor the sensors and signal any abnormal responses. In recent years, computer based leak detection through a Real-Time Transient Model to minimize spills has come into use. This technology can minimize spills from both new and old pipelines (Yoon and Mensik, 1988).

A similar technology for detecting leaks in oil and gas pipelines is termed Pressure Point Analysis (PPA). The method uses measured changes in the pressure and velocity of the fluid flowing in a pipeline to detect and locate leaks. PPA has successfully detected holes as small as 1/8-inch in diameter within a few seconds to a few minutes following a rupture (Farmer, 1989:23). Automated leak detection systems such as PPA operate 24 hours per day and can be installed at remote sites. Information from the sensors can be transmitted by radio, microwave, or over a hard wire system.

Offshore pipelines are inspected annually using side scan sonar to determine if any segments have become suspended due to bottom movement. Each pipeline surveyed is scanned two times to eliminate false readings. Any spans greater than 50 feet in length and more than one foot off the bottom are subsequently stabilized using diver installed sand-cement bags. The need for stabilization has reportedly declined over the past several years. The reason is not clear. It may be that the sand-cement bag stabilization program has gradually been successful in preventing additional wash outs or perhaps the Inlet bottom has become more stable (Belmar Management Services, 1993).

Onshore pipelines and facilities also receive regular inspections and maintenance. For example, Unocal has instituted a three-phase, multi-year program to update its Swanson River Oil Field facilities. The assessment phase included the use of specially trained dogs and infrared photography to inspect for leaks. The dogs sniff a special odorant that is inserted into temporarily shut-down lines. Infrared photos can locate plumes of warmer temperature areas, which would occur if oil were leaking into the soil surrounding the pipeline or tank. During the 1995 survey, the dogs located two natural gas valve boxes that were leaking (St. Pierre, 1996).

In the second phase, Unocal is taking corrective action to repair problems located by the assessment program and to update its tanks and pipelines. They are painting storage tanks inside with epoxy and are placing high density plastic liners in pipelines that were built before the advent of modern pigging and cathodic protection technologies (St. Pierre, 1996).

Preventive maintenance, in the third phase, includes installing improved cathodic protection, using corrosion inhibitors and continuing regular visual inspections. Unocal contracts local air services to overfly the facilities every two weeks, and field workers are always alert for problems (St. Pierre, 1996).

Marine Terminals. The fixed location of loading facilities at marine terminals improves oil spill response and contingency planning. Since these facilities are constantly staffed while in operation, leaks are easier to detect than with pipelines. If a leak occurs, the facility can be rapidly shut down and the spill contained. Spill prevention measures include extensive inspection programs, the monitoring of transfer operations, use of proper valves, overfill alarms, construction of secondary and tertiary containment systems around the tanks, facility security programs, training, and drug and alcohol testing of personnel. More detailed information regarding these programs are included in the oil discharge prevention and contingency plans for the Drift River facility and the Nikiski terminal.

Tanker Vessels. Tankers are the most cost effective and the only feasible method for transporting crude oil to destinations in the Pacific Rim. Federal legislation through OPA 90 requires the phase-out of single-hulled tankers in favor of double-hulled tankers by the year 2010. Double-bottomed tankers, where at least 30 percent of the area beneath the cargo tank length has two bottoms, are an interim measure.

The value of double-hulled tankers was recently illustrated off of Louisiana when one collided with a tug and barge flotilla. The tanker sustained a 100-foot by 4-foot gash but did not spill any of its 550,000 barrels of crude oil cargo. The 800-foot vessel safely discharged its shipment and sailed to a repair facility in Alabama. At the time of the accident, the tanker had a harbor pilot aboard and was being assisted by two tugs (OGJ, 1997a).

Tesoro currently contracts for the services of two double-bottomed tankers, the *Chesapeake Trader* and the *Potomac Trader,* to bring North Slope crude from Valdez and Cook Inlet crude from the west side of the Inlet to the Nikiski complex for refining. Recent changes at the Tesoro refinery may change the crude tanker traffic pattern. Beginning in January 1999 Tesoro will no longer transport North Slope crude into Cook Inlet. They will buy Cook Inlet crude and augment their refinery stock with partially refined crude from their refineries in Washington and Hawaii (ADN, 1998).

Cook Inlet crude carriers voluntarily follow many practices that also reduce the risk of oil spills. These include having two licensed officers or one licensed officer and one licensed marine pilot on deck at all times, keeping anchors ready for emergency use when traversing the Inlet, plotting fixes every 20 minutes, conducting unscheduled anchoring drills in the lower inlet, performing regular maintenance procedures and special inspections in preparation for the winter climate, incorporating special adaptations for tanker use in severe winter conditions, and scheduling transits to allow docking and undocking at the safest times when ice is present. Tankers routinely drop their anchors during docking maneuvers and may execute the emergency deployment of anchors to gain control over a disabled vessel. The enforcement of Winter Ice Rules also helps lower the risks associated with the transportation of crude oil.

Tankers moored at the Drift River terminal keep their main engines warm and slowly turning over to be ready for immediate use should they suddenly have to maneuver. Crews participate in spill prevention and response training and substance abuse testing. The reader is referred to the oil discharge prevention and contingency plans for Cook Inlet vessel operations, which contain more detailed information regarding spill prevention programs.

The U.S. Coast Guard has studied the issue of requiring an escort tug for Cook Inlet crude tankers and has conducted navigation safety meetings with Cook Inlet operators, concerned state and federal agencies and citizens advisory groups to review tanker operations practices. In March 1997 the Coast Guard found that there is "no historical justification for an escort system for Cook Inlet, nor is there sufficient risk posed by the tanker fleet that presently operates." The agency went on to recommend a standby tug for lower Cook Inlet that would provide navigational safety and fire-fighting capability for all marine traffic (CIRCAC, 1998). The Cook Inlet Regional Citizens Advisory Council (CIRCAC) also supports the placement of a standby tug in the lower Inlet and in November sent a letter to the Governor supporting the use of the Oil and Hazardous Substance Release Prevention and Response Fund to pay for a standby assist tug (CIRCAC, 1998). The funding and placement of a standby assist tug have not been resolved at this time.

3. Oil Spill Response

Incident Command System (ICS): The ICS structure is designed to organize and manage responses to incidents involving a number of interested parties in a variety of activities. Since oil spills usually involve multiple jurisdictions, the joint federal/state response plan incorporates a unified command structure in the oil and hazardous substance discharge ICS. The unified command usually consists of the Federal On-Scene Coordinator, the State On-Scene Coordinator, the Local On-Scene Coordinator and the Responsible Party On-Scene Coordinator. Industry and agency personnel in the operations, logistics, planning and finance sections of the incident command system gather information and make recommendations on objectives and strategies to the unified command. A Multi-Agency Coordination group made up of government agencies with local jurisdiction and other concerned parties also provides input to the unified command (ADEC et al., 1996).

The Unified Command jointly makes decisions on objectives and response strategies. However, only one Incident Commander is in charge of the spill response. The Incident Commander is responsible for implementing these objectives and response strategies developed by the operations, logistics finance and planning sections of the ICS (AS 46.04.200(b)(2) and (3)). The Responsible Party Incident Commander may remain in charge until or unless the Federal On-Scene Coordinator and the State On-Scene Coordinator decide that the Responsible Party (RP) is not doing an adequate job of response (ADEC et al., 1996). Government agency staff work with RP staff to provide necessary information and permits for the response operation and to monitor the activities performed by the RP.

Response Teams: The Alaska Regional Response Team (ARRT) monitors the actions of the Responsible Party. The ARRT is composed of representatives from 15 federal agencies and one representative agency from the state. The ARRT is co-chaired by the U.S. Coast Guard and Environmental Protection Agency. ADEC represents the state of Alaska. The team provides coordinated federal and state response policies to guide the Federal On-Scene Coordinator in responding effectively to spill incidents. The ARRT has developed guidelines regarding wildlife, in situ burning, and the use of dispersants. A working group is developing guidelines for the protection of cultural resources, which include archaeological and historic sites (ADEC et al., 1996).

Each operator identifies a response team for their facility, and each facility must have an approved spill contingency plan. The company teams provide on-site, immediate response to a spill event. The responders first attempt to stop the flow of oil and may deploy boom to confine oil that has entered the water. When the nature of the event exceeds the facility's resources, the Responsible Party calls in its response organization.

Cook Inlet Spill Prevention and Response, Inc. (CISPRI) is a major spill response organization in the Cook Inlet. The non-profit corporation was formed in October 1990 to provide personnel and oil spill equipment to respond to any kind of oil spill at the request of a member company. Operators of various facilities contract with CISPRI for response activities. The U.S. Coast Guard designated CISPRI a Class E Oil

Spill Removal Organization OSRO), which is the highest level of designation and is based on spill containment and removal requirements for an offshore/ocean response. CISPRI's response area extends from Palmer to the Barren Islands and into the Gulf of Alaska (CISPRI, 1997:1).

CISPRI's response center is located at Mile 26.5 North Spur Road near Nikiski, Alaska. In the event of a spill, the location serves as the emergency operations center for all federal, state and industry personnel. CISPRI's response actions include:

1. Notification and Initiation of Response. The CISPRI manager receives notification from the responsible party or the U.S. Coast Guard and in turn notifies the Operations Manager. The Operations Manager initiates a group call-out for CISPRI Technicians to respond within one hour. All CISPRI employees carry pagers for after-hours notification. In the event of a non-member or mystery spill, the U.S. Coast Guard will call the CISPRI manager and initiate a response.

2. Organization and Call-out: CISPRI personnel assemble at the designated staging area and begin response actions appropriate to the problem. Personnel are dispatched to the location of the spill for site assessment. In an offshore spill, response personnel would activate the *Banda Seahorse*, CISPRI's spill response vessel.

3. All CISPRI personnel are required to document their activities during an oil spill. The documentation covers actions taken, when and by whom directions were given, and where and by whom the action was performed. The Operations Section staff log who directed the action, what personnel and/or equipment was deployed, when it was deployed, and how long the action is expected to last.

CISPRI developed a technical manual that incorporates its emergency action plan, reporting and notification procedures, safety plan, communications, deployment strategies, response strategies, non-mechanical response options, description of its vessel, command system, realistic maximum response operating limitations, logistical support, response equipment, contractor information, training plans, and protection of environmentally sensitive areas. The technical manual is a part of the contingency plans prepared by each of CISPRI's member companies (CISPRI, 1997).

Other response organizations may operate in the Cook Inlet area if they meet U.S. Coast Guard and ADEC standards. Each organization may operate a little differently, but the objective is the same-to minimize the impact of an oil spill. Some operators maintain mutual aid agreements with other operators so that if the spill exceeds their individual capabilities, they may access other resources.

Response actions vary greatly with the nature, location and size of the spill. General response activities may include: 1) locate and stop the spill if possible; 2) estimate the spill amount, determine the substance's chemistry and estimate the trajectory; 3) determine what equipment would most effectively recover spilled oil; 4) mobilize appropriate equipment to confine spilled oil or to protect especially sensitive areas from oiling; and 5) assess the damage to oiled areas, develop a plan for cleanup and implement it. Response equipment might include boats, earth-moving equipment, airplanes, helicopters, boom, skimmers, sorbants, and dispersants application machinery. The responsible party and its contractors usually perform response activities with assistance and monitoring by federal and state agencies.

The history of crude oil spills in Cook Inlet and the low to moderate potential for discovering new reserves indicates that there is low to moderate probability of a major spill occurring as a result of this areawide sale. However, the environment of Cook Inlet can present extremes that might make it difficult to effectively contain and cleanup a major spill. The impact on the sensitive environments of Cook Inlet could be severe.

Spill responders in Cook Inlet face a daunting task. Strong currents and large tides in the Inlet move oil rapidly. Winter ice, darkness and severe weather can endanger responders and interfere with the recovery of spilled oil. Thick ice could block access to spilled oil; while broken ice might actually help capture floating oil. Darkness increases the difficulty in observing oil on water. Severe weather could put responders at risk. Chapter Two contains a thorough description of the challenging environment in Cook Inlet.

4. Regulation of Oil Spill Prevention and Response

Federal Statutes and Regulations. Section 105 of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA) (42 U.S.C. ß9605), and section 311(c)(2) of the Clean Water Act as amended (33 U.S.C. ß 1321(c)(2)) require environmental protection from oil spills. CERCLA regulations contain the National Oil and Hazardous Substances Pollution Contingency Plan (40 C.F.R. ß 300). Under these regulations, the operator of an oil facility must plan to prevent and immediately respond to oil and hazardous substance spills and must be financially liable for any spill cleanup. If the pre-designated Federal On-Scene Coordinator (FOSC) determines that neither timely nor adequate response actions are being implemented, the federal government will take charge of the response then seek to recover cleanup costs from the responsible party.

The Oil Pollution Act of 1990 (OPA 90) requires the development of facility and tank vessel response plans by the industry and government planning to coordinate federal, regional, and local government preparation efforts with the industry. OPA 90 amended the Clean Water Act (Section 311(j)(4)) which established area committees and area contingency plans as the primary components of the national response planning structure. In addition to human health and safety, these area committees have three primary responsibilities:

1. prepare an area contingency plan;
2. work with state and local officials on contingency planning and preplanning of joint response efforts, including procedures for mechanical recovery, dispersal, shoreline cleanup, protection of sensitive areas, and protection, rescue and rehabilitation of fisheries and wildlife; and
3. work with state and local officials to expedite decisions for the use of dispersants and other mitigating substances and devices.

In Alaska, the area committee has incorporated state and local agency representatives, and the jointly prepared plans coordinate the response activities of the various governmental entities that have responsibilities regarding oil spill response. The area contingency plan for Alaska is the Unified Plan and is discussed below. Since Alaska is so large and geographically diverse, the federal agencies have found it necessary to prepare sub-area contingency plans. These plans have been combined with the government contingency plans required by state law and are discussed later in this section.

OPA 90 requires that oil facility operators provide proof of financial responsibility. The Oil-Spill Financial Responsibility (OSFR) regulations are administered by the Minerals Management Service (MMS) and apply to facilities used to explore for, produce or transport crude oil or natural gas located on the Outer Continental Shelf (OCS), state waters seaward from the line of ordinary low water along that portion of the coast that is indirect contact with the open sea, and certain coastal inland waters. The OSFR requirements apply to facilities that have a worst-case oil spill discharge potential of greater than 1,000 bbls. The potential responsible party’s OSFR proof may take several forms, including insurance and surety bonds. In general, the amount of required coverage ranges from $10 to $150 million, depending on the calculated volume of the facility’s worst-case oil spill discharge potential.

OSFR REQUIREMENTS FOR NON-OCS LANDS

WORST CASE OIL SPILL DISCHARGE VOLUME	AMOUNT OF OSFR
Over 1,000 but not more than 10,000 bbls	$10 million
Over 10,000 but not more than 35,000 bbls	$35 million
Over 35,000 but not more than 70,000 bbls	$70 million
Over 70,000 but not more than 105,000 bbls	$105 million
Over 105,000 bbls	$150 million

These federal requirements apply to facilities on the Outer Continental Shelf and to state submerged lands as well. The State of Alaska has a well-established financial responsibility program that differs from the federal program in both the type of facilities covered and the amount of financial responsibility required. The state program is discussed later in this section. The programs are separate and distinct until specific agreements are developed to coordinate the two programs. State and federal agencies are working together to accomplish this.

OPA 90 also created two citizen advisory groups, the Prince William Sound and the Cook Inlet Regional Citizens Advisory Councils. These non-profit organizations provide citizen oversight of terminal and tanker operations that may affect the environment in their respective geographic areas. They also foster a long term partnership between industry, government and citizens and carry out responsibilities identified in section 5002 of OPA 90. The groups provide recommendations on policies, permits and site-specific regulations for terminal and tanker operations and maintenance and port operations, monitoring terminal and tanker operations and maintenance, and reviewing contingency plans for terminals and tankers and standards for tankers. The geographical areas the two organizations cover are Prince William Sound and Cook Inlet, and the two groups actively participate in joint projects.

The Prince William Sound Regional Citizens Advisory Council (PWSRCAC) consists of 18 member organizations, including communities impacted by the *Exxon Valdez* oil spill, a Native regional corporation and groups representing fishing, aquaculture, environmental, tourism and recreation interests in the impacted area. PWSRCAC is certified under OPA 90 and operates under a contract with Alyeska. The contract, which is in effect as long as oil flows through TAPS, guarantees the council’s independence, provides annual funding, and ensures the PWSRCAC the same access to terminal facilities as state and federal regulatory agencies.

The Cook Inlet Regional Citizens Advisory Council (CIRCAC) consists of 13 members organizations from the cities of Anchorage, Homer, Kenai, Kodiak and Seldovia; the boroughs of Kenai and Kodiak; native groups; commercial fishermen; and aquaculture, tourism, recreation and environmental interest groups. Nine ex-officio members from state and federal agencies also sit on the council. The Cook Inlet council carries out its work through two committees, the Environmental Monitoring Committee (EMC) and the Prevention, Operations and Safety (PROPS) Committee. The council initiated a pilot environmental monitoring program in 1993 and has maintained the program through 1998.

Alaska Statutes and Regulations. ADEC is the state agency responsible for implementing state oil spill response and planning regulations under AS†46.04.030. The Departments of Fish and Game and Natural Resources assist ADEC in these efforts by providing expertise and information. The industry must file oil spill prevention and contingency plans with ADEC before operations commence. ADNR and ADF&G review and comment to ADEC regarding the adequacy of the industry oil discharge prevention and contingency plans (C-plans).

Industry Contingency Plans. According to both federal and state law oil and gas facilities must have an approved C-plan before beginning operations. AS 46.04.030 provides that no person may:

1. operate an oil terminal facility, a pipeline, or an exploration or production facility, a tank vessel, or an oil barge, or
2. permit the transfer of oil to or from a tank vessel or oil barge, unless an oil discharge prevention and contingency plan has been approved by ADEC, and the operator is in compliance with the plan (AS 46.04.030(a),(b),(c)).

Parties with approved plans are required to have sufficient oil discharge containment, storage, transfer, cleanup equipment, personnel, and resources to meet the response planning standards for the particular type of facility, pipeline, tank vessel, or oil barge (AS 46.04.030(k)). Examples of these standards are:

- The operator of an oil terminal facility must be able to "contain or control, and clean up" a spill volume equal to that of the largest oil storage tank at the facility within 72 hours. That volume may be increased by ADEC if natural or manmade conditions exist outside the facility which place the area at high risk (AS 46.04.030(k)(1)).

- Operators of exploration or production facilities, or pipelines, must be able to "contain, control, and cleanup the realistic maximum oil discharge within 72 hours." (AS 46.04.030(k)(2)). The "realistic maximum oil discharge" means "the maximum and most damaging oil discharge that [ADEC] estimates could occur during the lifetime of the tank vessel, oil barge, facility, or pipeline based on (1) the size, location, and capacity; (2) ADEC's knowledge and experience with such; and (3) ADEC's analysis of possible mishaps." (AS 46.04.030(q)(3)).

- For crude oil tank vessels and oil barges with a cargo volume of less than 500,000 bbls, the plan holder must be able, at a minimum, to contain or control, and clean up a discharge of 50,000 bbls within 72 hours (AS 46.04.030(k)(3)(A)). For capacities of 500,000 bbls or more, the cleanup volume must be 300,000 bbls within 72 hours (AS 46.04.030(k)(3)(B)). Additionally, all crude oil tank vessel operators must also maintain equipment, personnel, and other resources as necessary to control or contain and clean up a realistic maximum discharge within the shortest possible time (AS 46.030(k)(3)(C)).

Discharges of oil or hazardous substances must be reported to ADEC on a time schedule depending on the volume released, whether the release is to land or to water, and whether the release has been contained by a secondary containment or structure. For example, any discharge of oil to water in excess of 55 gallons on land not within an impermeable secondary containment area or structure must be reported as soon as the operator has knowledge of the discharge (18 AAC 75.300(a)(1)(B) and (C)).

The discharge must be cleaned up to the satisfaction of ADEC, using methods approved by ADEC. If ADEC determines that clean up efforts are inadequate, the department will either order the person engaged in cleanup operations to use additional methods or to cease cleanup activities, or authorize other agents to begin cleanup activities, or both (18 AAC 75.337(a)). TADF&G and ADNR advise ADEC regarding the adequacy of cleanup.

A C-plan must describe the existing and proposed means of oil discharge detection, including surveillance schedules, leak detection, observation wells, monitoring systems, and spill-detection instrumentation. AS 46.04.030; 18 AAC 75.425(e)(2)(E). C-plans for exploration facilities should include a description of methods for responding to and controlling blowouts; the location and identification of oil spill cleanup equipment; the location and availability of suitable drilling equipment; and an operations plan to mobilize and drill a relief well. If development and production should occur, additional contingency plans must be filed for each facility prior to commencement of activity, as part of the permitting process. Any vessels transporting crude oil from the potential development area must also have an approved contingency plan. A C-plan and its preparation, application, approval, and demonstration of effectiveness requires a major effort on the part of facility operators and plan holders. The C-plan must include a response action plan, a prevention plan, and supplemental information to support the response plan (18 AAC 75.425). These plans are described below.

The Response Action Plan (18 AAC 75.425(e)(1) Part 1) must include an emergency action checklist of immediate steps to be taken if a discharge occurs. The checklist must include:

1. names and telephone numbers of people within the operator's organization who must be notified, and those responsible for notifying ADEC;
2. information on safety, communications, and deployment, and response strategies;
3. specific actions to stop a discharge at its source, to drill a relief well, to track the location of the oil on open water, and to forecast the location of its expected point of shoreline contact to prevent oil from affecting environmentally sensitive areas;
4. procedures for boom deployment, skimming or absorbing, lightering, and estimating the amount of recovered oil;
5. plans, procedures, and locations for the temporary storage and ultimate disposal of oil contaminated materials and oily wastes;
6. plans for the protection, recovery, disposal, rehabilitation, and release of potentially affected wildlife; and
7. if shorelines are affected, shoreline clean up and restoration methods.

The Prevention Plan (18 AAC 75.425(e)(2) Part 2) must:

1. include a description and schedule of regular pollution inspection and maintenance programs;
2. provide a history and description of known discharges greater than 55 gallons that have occurred at the facility, and specify the measures to be taken to prevent or mitigate similar future discharges;
3. provide an analysis of the size, frequency, cause, and duration of potential oil discharges, and any operational considerations, geophysical hazards, or other site-specific factors, which might increase the risk of a discharge, and measures taken to reduce such risks.

The Supplemental Information Section (18 AAC 75.425(e)(3) Part 3) must:

1. include bathymetric and topographic maps, charts, plans, drawings, diagrams, and photographs, which describe the facility, show the normal routes of oil cargo vessels, show the locations of storage tanks, piping, containment structures, response equipment, emergency towing equipment, and other related information;
2. show the response command system; the realistic maximum response operation limitations such as weather, sea states (roughness of the sea), tides and currents, ice conditions, and visibility restrictions; the logistical support including identification of aircraft, vessels, and other transport equipment and personnel;
3. include a response equipment list including containment, control, cleanup, storage, transfer, lightering, and other related response equipment;
4. provide non-mechanical response information such as in situ burning or dispersants, including an environmental assessment of such use; and
5. provide a plan for protecting environmentally sensitive areas and areas of public concern.

The current statute allows the sharing of oil spill response equipment, materials, and personnel among plan holders. ADEC determines by regulation the maximum amount of material, equipment, and personnel that can be transferred, and the time allowed for the return of those resources to the original plan holder (AS 46.04.030(o)). The statute also requires the plan holders to "successfully demonstrate the ability to carry out the plan when required by [ADEC]" (AS 46.04.030(r)(2)(E)). ADEC regulations require that exercises shall be conducted to test the adequacy and execution of the contingency plan. No more than two exercises are required annually, unless the plan proves inadequate. ADEC may, at its discretion, consider regularly scheduled training exercises as discharge exercises (18 AAC 75.485(a) and (d)).

Financial Responsibility. Holders of approved contingency plans must provide to the state proof of their financial ability to respond (AS 46.04.040). Financial responsibility may be demonstrated by one or a combination of 1) self-insurance; 2) insurance; 3) surety; 4) guarantee; 5) approved letter of credit; or 6) other ADEC-approved proof of financial responsibility (AS 46.04.040(e)). Operators must provide proof of financial responsibility acceptable to ADEC as follows:

- for crude oil terminals: $50 million in damages per incident.
- for a non-crude oil terminal: $25 per incident for each barrel of total non-crude oil storage capacity at the terminal or $1 million, whichever is greater, with a maximum of $50 million.
- for pipelines and offshore exploration or production facilities: $50 million per incident.
- for onshore production facilities: $20 million per incident.
- for onshore exploration facilities: $1 million per incident.
- for crude oil vessels and barges: $300 per incident, for each barrel of storage capacity or $100 million, whichever is greater.
- for non-crude oil vessels and barges: $100 per barrel per incident or $1 million, whichever is greater, with a ceiling of $35 million AS 46.04.040(a),(b),(c).
- The coverage amounts are adjusted every third year based on the Consumer Price Index. AS 46.04.045.

Government Contingency Plans. In accordance with AS 46.04.200, ADEC must prepare, review, and revise the statewide master oil and hazardous substance discharge prevention and contingency plan. The plan must identify and specify the responsibilities of state and federal agencies, municipalities, facility operators, and private parties whose property may be affected by an oil or hazardous substance discharge. The plan must incorporate the incident command system, identify actions to be taken to reduce the likelihood of occurrence of "catastrophic" oil discharges and "significant discharges of hazardous substances" (not oil), and designate the locations of storage depots for spill response material, equipment, and personnel. The state master plan has been combined with the federally required area plan to create the "Alaska Federal/State Plan for Response to Oil and Hazardous Substance Discharges/Releases," also known as the Unified Plan. (ADEC, 1996).

ADEC must also prepare and review and revise a regional master oil and hazardous substance discharge prevention and contingency plan (AS 46.04.210). The regional master plans must contain the same elements and conditions as the state master plan but are applicable to a specific geographic area. The state regional plans are developed in conjunction with the federally required sub-area plans as "Sub-Area/Regional Contingency Plans" for each of the ten designated contingency planning areas. The "Cook Inlet SubArea Contingency Plan" was finalized July 1997 and is reviewed and revised on a regular basis.

State and federal agencies, the industry and citizens groups are currently exploring the possibility of preparing geographic response plans (GRP) for the Cook Inlet. GRPs are site-specific response plans for protecting environmentally sensitive areas and other areas of public concern from the damage caused by an oil or hazardous substance spill. The plans would provide immediate decisive action for specific areas by identifying sensitive areas and resources and specifying the response equipment and tactics that would be used to protect or cleanup those areas.

Mitigation Measures

Recognition of the difficulties of containment and clean-up of oil spills in the Cook Inlet area has encouraged innovative and effective methods of preventing possible problems and handling them if they arise. State and federal agencies, concerned citizens groups and the oil industry are continually researching oil spill prevention and response techniques. Although the risk of a spill cannot be reduced to zero, such risk can be minimized through preventive measures, monitoring, and rigorous response capability. In addition to addressing the prevention, detection, and cleanup of releases of oil, Mitigation Measure 1 requires that lessees' contingency plans address the method to be used to detect, respond to, and control blowouts. Also under this measure, contingency plans must identify the location of oil spill cleanup equipment; the location and availability of suitable alternative drilling equipment; and identify a plan of operations to mobilize and drill a relief well.

D. Effects on Water Quality

This section begins with a description of the byproducts of drilling, and current disposal practices of industrial waste. The second part describes water quality for marine waters of the sale area with an emphasis toward the ongoing search for hydrocarbons and other industry pollutants. This is followed by a description of the discharge permit system currently in place for existing operations. Finally, the quality of surface and groundwater is discussed with emphasis on past and current waste disposal methods.

Several mitigation measures would protect water quality and reduce or prohibit activities that could have adverse impacts on marine and fresh water resources. A summary of these is presented at the end of this section (See Chapter Nine for a complete list of mitigation measures).

1. Drilling and Use of Water

Drilling methods for onshore and offshore wells are similar, but disposal of byproducts varies. For onshore operations, most drilling wastes are disposed of under ADEC's solid waste disposal program, or shipped out of state; however, reinjection is the preferred method of drilling fluid disposal. For offshore operations, non-hazardous waste that cannot be returned to the subsurface is treated and discharged into Cook Inlet under the NPDES permit.

a. Drilling Muds and Produced Water

Byproducts of drilling and production activities include muds and cuttings, produced water and associated wastes. During drilling and after a well is in production, water comes to the surface mixed with oil and gas, and must be separated before further refining. Drilling employs the use of carefully mixed fluids, called muds. Cuttings are small fragments of rock up to an inch across that are dislodged and carried to the surface by drill muds. Drilling muds are mostly water-based mixtures of clay and other earthen materials, such as almond husks, which are used to cool and lubricate the drilling bit, and facilitate the drilling action, flush out cuttings within the well bore, seal off cracks in down-hole formations to prevent the flow of drilling fluids into these formations, and maintain reservoir pressure. Chemicals may be added to maximize the effectiveness of drilling and casing. (See Table 5.1.) Oil-based muds and synthetic-based muds may also be used depending on the well depth, well diameter, and subsurface formations (NRC, 1983) (Veil, Burke & Moses, 1996).

Produced water contains mostly natural substances such as clay and sand, which is mixed with oil, water and gas, found in the subterranean strata. Produced waters are usually saline with some level of hydrocarbons. Associated wastes are other production fluids, such as tank bottom sludges, well work-overs, gas dehydration processes, tank wastewater and other residues which are considered non-hazardous (low-toxicity) by the EPA. Like drilling muds, chemicals may be added to produced water to remove harmful bacteria, halt corrosion, break up solids, prevent scale build up, and break oil/water emulsions (EPA, 1995b).

According to a 1993 EPA report, the use of water-based muds generates 7,000 to 13,000 barrels of waste per well, and depending on the depth and diameter of the well, 1,400 to 2,800 of those are cuttings. Oil-based mud volumes are generally less than water-based, because they are more efficient, and oil-based muds may be reconditioned, reused, and re-sold. Newer synthetic-based muds produce even less waste, improve drilling efficiency, are reusable, and have advantages in environmental protection over oil or water-based muds (Veil, Burke & Moses, 1996:50). Discharge of untreated oil-based muds into any water column violates federal and state pollution laws.

Table 5.1 Additives of Drilling Fluids

	Common additive	Use
Weighting material	Barite (barium sulfate ore)	adds density and counters formation pressures
Viscosifiers	Bentonite clay (mostly sodium montmorillonite)	removes cuttings, prevents fluid loss, helps seal wellbore
Natural & Synthetic Polymers	Bentonite and drilled clays, Corn and potato starch, modified starch, natural gums	mud cake, prevent fluid loss, cuttings transport, hydraulics
Thinners	plant tannins, polyphosphates, lignitic materials	reduce temperature effects, reduce viscosity
pH and Ion Control	soda ash, baking soda, sodium hydroxide	control corrosion, remove harmful gas (H2S)
Lubricants	natural and synthetic oil-based compounds	reduce friction in wellbore
Bacteria Control Agents	Depends on ability to meet effluent guidelines	mitigate fermentation of organics in drill system
Surfactants	salts, soaps, fatty acid derivatives	emulsifier, wetting agent, foamers, defoamers, reduce clay hydration

Source: NRC, 1983

b. Current Waste Treatment and Disposal Practices

Although current offshore operations may discharge fluids into the water column, the preferred method of waste disposal is through underground injection for both onshore and offshore operations. Surface disposal of muds and cuttings in reserve pits is discouraged. Wastewater, including sanitary and domestic graywater is also treated to meet effluent guidelines before discharge.

Most oilfield wastes are considered non-hazardous and waste fluids are recycled, filtered and treated before reinjection or disposal. Cuttings and waste fluids must be made non-hazardous before injection. For offshore operations, treated or non-hazardous muds and waters are discharged into Cook Inlet from production platforms. Before discharging muds and cuttings, tests are conducted to determine if the discharge is within permitted levels. Maximum acceptable levels of toxicity in discharges are established by the U.S. Congress and the EPA under the National Pollution Discharge Elimination System (NPDES) permit described below. This permit regulates discharges into waterbodies by industries and municipalities. Hazardous wastes are regulated under separate laws and must be disposed of safely.

Produced water is treated using heat, gravity settling and gas flotation devices to remove hydrocarbons. After treatment, produced water is reinjected into either the oil-bearing formation to maintain pressure and enhance recovery or into an approved disposal well. Cuttings disposal is done through grinding and injecting on-site or cuttings are transported to an approved disposal site. Cuttings disposal can cost more than the total cost to drill a well (Powell, 1996).

The EPA's Underground Injection Control Program, administered by the AOGCC, insures proper and safe handling and disposal of drilling wastes. The AOGCC functions as the regulatory agency overseeing the underground operation of the Alaska oil industry on private and public lands and waters. The Commission administers the Underground Injection Control (UIC) program for oil and gas wells, acts to prevent waste of oil and gas resources and ensure maximum recovery, and protects subsurface property rights. All disposal wells inject fluids deep beneath any drinking water aquifer.

2. Marine Water Quality

Some drilling muds and cuttings, and other non-hazardous wastes are discharged into the inlet as authorized by an EPA National Pollution Discharge Elimination System (NPDES) permit. With the exception of mixing zones adjacent to out-fall pipes, field study and monitoring results described below indicate that as a result of rapid settling and dilution, marine discharges do not cause harmful effects in the water column. Mixing zones are predetermined, specifically designated portions of water where the discharge is sufficiently diluted to meet water-quality standards by the time it reaches the border of the zone.

The upper Cook Inlet is a dynamic, high-energy environment. The normal tide cycle has an average height ranging from about 10 feet near the mouth of the inlet to approximately 30 feet at Anchorage. Tide currents of up to eight knots are common near the Forelands. Cook Inlet waters are well mixed vertically, because of strong tidal current speeds. There is a small net southward tidal component, 10 to 15 percent of the speed of the tidal currents, which flushes water out of the upper inlet (ADL, 1991).

Discharges from platforms are diluted rapidly in the marine environment. Computer modeling reveals that produced water effluents would generally be diluted rapidly to concentrations that pose no risk of acute or chronic toxicity at the edge of the mixing zones. Dissolved and suspended solid materials discharged from the platforms will be diluted and transported with suspended glacial sediments through the lower inlet and into Shelikof Strait and the Outer Continental Shelf of the Gulf of Alaska. (ADL, 1991). Ongoing monitoring and sampling studies may confirm or reject conclusions of earlier studies of the effects of drilling discharge on Cook Inlet.

a. Presence of Hydrocarbons and Metals

Studies described below indicate produced water, muds, and cuttings discharges have not significantly degraded Cook Inlet water quality or the health of its dependent resources. Considering new facilities' discharge restrictions (see NPDES permit description below), the cumulative effect on the Cook Inlet marine environment from post-sale activities would likely be insignificant.

Between 1957 and 1972, a period beginning with Cook Inlet oil discovery and ending with the passage of the Clean Water Act (33 U.S.C.A. §§ 1251 to 1387), interest in the impacts of oil production activities on marine water quality of Cook Inlet grew. In recent years, since the federal Oil Pollution Act (OPA) of 1990, and in years past, several environmental studies have been conducted on Cook Inlet waters.

In 1976, NOAA (Burrell et. al.,1978) investigated baseline minerals present in suspended solids on Alaska's continental shelf including sites in Cook Inlet (ENRI, 1995:62). In the same year, a University of Alaska study was also conducted (Shaw & Lotspeich, 1977). Samples were collected and analyzed by a contractor for Greenpeace in 1991 (NTCF, 1991). The Minerals Management Service (MMS) conducted a water and sediment quality assessment in preparation for an Outer Continental Shelf (OCS) Lease Sale in 1993. An ongoing study of water and benthic sediment quality began in the same year under the direction of CIRCAC. Other studies are currently underway, and results are forthcoming. These studies are discussed below. In addition to industry sponsored tests mandated by the EPA and ADEC, other independent observations have been reported.

Most studies look for acute or chronic levels of key indicators, such as heavy metals and hydrocarbons in sediments and marine life. Filter feeding bi-valves accumulate toxins in their tissues. Researchers test the tissues of animals after being exposed to the water column. They also look for variability in these levels between sampling stations. Chemical analysis includes the detection of polycyclic aromatic hydrocarbons (PAH's), which leave a unique and traceable signature. This method for 'fingerprinting' the exact source of petroleum hydrocarbons has been used extensively in studies of the *Exxon Valdez* Oil Spill.

Hydrocarbon Sources	
PAH-	Polycyclic aromatic hydrocarbons
Petrogenic-	Resulting from natural geologic processes which originally form petrochemicals (petroleum based)
Pyrogenic-	Resulting from the activity of fire or very high temperature(combustion based fossil fuels or creosote)
Diagenic-	Resulting from alteration by microbial or chemical processes (transformed materials)
Biogenic-	Produced by living organisms (includes diagenic sources)

Adapted from KLI, 1995.

Composition of bottom and suspended sediments in upper Cook Inlet differs from the lower Inlet due to input sources: glacial river systems to the north and Gulf of Alaska current input to the south. Four major river systems supply about 70 to 80 percent of the fresh water input in Cook Inlet: Susitna, Matanuska, Knik, and Beluga (ENRI, 1995:3). Northern Inlet waters are characterized by higher concentrations of suspended particulate matter, primarily glacial rock flour (aluminosilicate minerals), due to dynamic tidal mixing and high sediment loads of rivers. Suspended particulate matter concentrations range from 100 parts per million (ppm) near the Forelands to 1 ppm near the Inlet entrance (MMS, 1995: III.A.7).

Industrial discharges of metals from oil and gas facilities and runoff from the city of Anchorage include zinc, barium, cadmium, and mercury. These mineral discharges are monitored at known point sources, including oil production facilities, the Point Woronzof Wastewater Treatment Plant, military bases, fish processors, and municipalities. Natural levels of these minerals also occur. Hydrocarbons are discharged into the inlet by streams and rivers as a result of the erosion of sedimentary rocks containing coal, and from natural seeps (MMS, 1995: III.A.9). Hydrocarbons from point discharges and non-point sources (runoff) throughout the Cook Inlet basin also enter the inlet.

In 1976, researchers with the University of Alaska Institute of Marine Science conducted a study looking for hydrocarbons in biota and sediments of Cook Inlet. Seaweed, bivalve, and sediment samples were collected from sites in Mud, Dogfish, and Kasitsna Bays and near the mouth of the Douglas River. Biogenic hydrocarbons were detected in sediments at all sampling sites. Differences in sediment grain size explained the variability in hydrocarbon levels between sites. Analysis of the seaweeds (*Fucus sp*. and *Macoma sp*.) indicated the presence of biogenic lipid source hydrocarbons, and variability between sites was attributed to species diet. "None of these plant samples show evidence of petroleum; their hydrocarbons appear to be the products of their own metabolism." (Shaw & Lotspeich, 1977:12) Analysis of mussel tissues (*Mytilus sp*.) from Mud Bay, adjacent to the Homer spit, did contain low concentrations of hydrocarbons characteristic of weathered petroleum, although the predominate source of hydrocarbons in mussel tissue samples were biogenic (Shaw & Lotspeich, 1977).

A 1991 report on chemical analysis of Cook Inlet sediments was prepared for Greenpeace Alaska by the National Toxics Campaign Fund. Sediments were collected in July 1991 near the mouth of the Drift River and in Trading Bay. Samples were then tested for PAH's and metals, including beryilium, arsenic, and barium. PAH's were not detected (greater than or equal to 0.3 ppm) in any of the samples. No beryilium or arsenic was detected, although "higher than average" concentrations of barium were detected in all samples. Levels of barium in the Trading Bay samples were twice that of samples collected from the Drift River site (NTCF, 1991).

The 1993 MMS study attempted to establish baseline information on the occurrence of petroleum hydrocarbons, naturally occurring radioactive materials, and trace metals in the inlet. Seawater, biota and sediments were collected for detailed chemical and biological analysis. Samples were taken in the vicinity of petroleum production in northern Cook Inlet as well as in Kachemak and Kamishak Bays. These sites had been previously sampled during the Outer Continental Shelf Environmental Assessment Program by the MMS in the late 1970's. Although concentrations of metals in suspended sediments appeared to be higher 17 years after the NOAA study, the detection efficiency of the modern method is much higher than that used by Burrell and others (ENRI, 1995:62). Concentrations of metals (cadmium, copper, and zinc) in mussel tissues were nearly identical to levels found in 1977. Concentrations of terrestrial-source mercury were reported at sampling stations in the northern Inlet that were higher than the EPA designated chronic level (0.025 micro grams per liter), but well below the acute toxicity level (ENRI, 1995:54). Researchers concluded that, "[t]he physical, chemical, and bioassay results of this study show that Cook Inlet has very low environmental concentrations of hydrocarbons and that sediments and water are generally free from toxicity. Results also show no immediate evidence of heavy metal pollution in Cook Inlet." (ENRI 1995: xv)

In response to the Congressional Oil Pollution Act (OPA) of 1990, CIRCAC initiated an environmental study for the Inlet in 1993. The primary aim of the ongoing study was to determine if oil industry operations in Cook Inlet are having adverse effects on the surrounding ecosystem, and if so, to document their sources, magnitude, and distribution patterns (ADL, 1995a: viii). Methodology consisted of collecting and analyzing bivalves, and sediment and water quality samples. Hydrocarbon collector devices and blue mussels were used to evaluate hydrocarbon concentrations in the water column. Clams from Kamishak and Kachemak Bays were also collected for establishing a reference or baseline level of hydrocarbons occurring in their tissue. As with the MMS study, sample sites were located near possible point sources of pollution, such as the produced water out-fall in Trading Bay, as well as at locations some distance from industrial activity.

Analysis of the mussels and hydrocarbon collector devices showed some accumulation of hydrocarbons from the water column. The clams were essentially free of PAH's. Researchers concluded that, "The accumulation patterns indicated a low-level background input of hydrocarbons of a source apparently not linked to the Trading Bay produced water discharge." (ADL, 1995a; p. ix).

Quantities of petroleum hydrocarbons in sediments and shellfish tissues sampled in the study were below levels known to cause adverse biological effects in most marine organisms and were characteristic of an uncontaminated coastal and offshore environment (ADL, 1995a:x).

Sampling conducted in 1994 produced similar results. PAH concentrations in most sediment samples were characteristic of naturally occurring hydrocarbons and representative of background or baseline levels. Although sediments throughout the sampling region contained low levels of hydrocarbons, their toxicity to sediment dwelling organisms did vary with higher toxicity in southern inlet sampling stations, particularly in Kachemak Bay. Toxicity was not due to hydrocarbon levels in the sediment and may be due to the presence of compounds and substances not measured in the study, such as metals, naturally occurring inorganic compounds or municipal wastes (ADL, 1995b:iv).

In 1995, CIRCAC conducted a monitoring study that complimented earlier work while introducing some new methods. Marine water samples, sediments and halibut were collected and tested for presence of hydrocarbons. Samples were taken from Trading Bay, East Forelands, Kachemak Bay, Kamishak Bay, and a site near the Barren Islands. Results of the 1995 program are similar to previous years. "Hydrocarbon concentrations in sediments from all 1995 program stations are considerably lower than the amount expected to cause adverse effects in animals." (KLI, 1996:vi)

Chemical analysis of the halibut indicated a level of exposure to hydrocarbons comparable to areas considered uncontaminated (KLI, 1996:vi). No significant changes in any key indicators of oil and gas industry pollution (metals, PAH's, toxicity ranges) in the three years of sampling were found. However, some anomalies were encountered and hydrocarbon levels in man-made collectors in Trading Bay were higher than collectors positioned in Kachemak Bay and near the East Forelands (KLI, 1995:32).

A 1997 report issued by the Cook Inlet Keeper, an environmental watchdog group, describes the range of pollution sources, which may affect Cook Inlet water quality, and identifies risks posed by growing human population and urbanization. This non-technical report asserts that fish and sediment studies looking for hydrocarbon pollution have been inconclusive and that longer-term testing is needed before conclusions can be drawn (CIK, 1997:32). Additionally, Cook Inlet Keeper has initiated a citizen-based water quality sampling program.

In the search for the effects of industrial discharge, MMS has contracted for a three-year monitoring study of sediment quality in depositional areas of Shelikof Strait and outermost Cook Inlet. The $1.5 million 3-year study began in 1997. The study examines whether there has been an accumulation of biologically significant levels of pollutants in depositional areas down current of Cook Inlet development. Researchers are comparing the chemical fingerprints of pollutants from sediment samples to fingerprints of possible sources. Twelve possible sources will be fingerprinted, including Cook Inlet crude oil, produced waters from production platforms, natural oil seeps, MOA sewage out-fall, and water from the Homer harbor. Measured pollutant levels will be compared to established or proposed quality criteria to estimate environmental risk (MMS, 1997). Sampling was conducted in 1997.

The objectives of MMS's study are to:

- Evaluate the Shelikof Strait and Outermost Cook Inlet as potential depositional areas or "traps" for oil industry contaminants;

- Determine whether contaminant concentrations in sediments of these areas pose an environmental risk;

- Determine whether contaminants in these areas have accumulated relative to preindustry concentrations;

- Determine whether any increases can be correlated with specific discharge events or activities (e.g., the *Exxon Valdez* oil spill).

Results of the study to date characterize the complex picture of potential contamination from sources beyond oil and gas exploration and production activities:

Estimation of current impact and prediction of future environmental risk and impacts are complicated by the existence of multiple sources of similar pollutant assemblages to the region beyond E&P [exploration and production] operations. Natural oil seepages are common in the area and are known to represent an important part of the hydrocarbon assemblage in the sedimentary environments of areas of the Gulf of Alaska. Oil spillages, especially that from the Exxon Valdez spill are potential contributors, though no evidence of the impact this spill, in particular, has been observed in the subtidal sediments of Cook Inlet or Shelikof Strait. Tremendous quantities of suspended material are swept into the region from glacial runoff with associated metals and hydrocarbons. Municipal discharges and other permitted industrial (e.g. seafood processing) discharges contribute important quantities of wastes over time to the immediate coastal areas and presumably to the area's deeper depositional locations. (ADL, 1998:ES-1)

Results from the study's Interim report (ADL, 1998) are presented below.

Surface sediments of outermost Cook Inlet and the Shelikof Strait "are potential traps for contaminants from oil and gas production activities in upper Cook Inlet. However, based on evaluations of the organic and inorganic data, no contamination in the surface sediments from oil and gas production activities in upper Cook Inlet was identified. However, elevated Hg [mercury] concentrations were identified in Kachemak Bay due to local anthropogenic sources." (ADL, 1998:ES-4)

Concentrations of metals and organics (i.e., PAHs) in sediments in outermost Cook Inlet and Shelikof Strait have not increased significantly over the past 25 to 50 years. (ADL, 1998:ES-4)

The composition of metals in the sediments of outermost Cook Inlet and Shelikof Strait do not appear to have changed over the last 25 to 50 years. "The composition of hydrocarbons in sediment cores show subtle changes in outermost Cook Inlet over the past 25 to 50 years, but these changes do not appear to be correlated with petroleum production activities or spills." (ADL, 1998:ES-4)

In terms of risk to biota and the benthic environment, [t]he first sampling season has provided a picture of contaminants and potentially toxic trace substances in the environment at very low concentrations with an attendant low biological risk. The concentrations of trace metals are consistently below the risk levels identified by Long and Morgan (1990), except for Ni, which has a crustal abundance higher than the designated effects range low (ERL) and effects range median (ERM) concentrations. The concentrations of PAH detected in sediments are also below the ERLs identified by Long and Morgan (1990). The P450 RGS results also indicated low to negligible biological risk associated with extractable organic compounds, namely PAH, in the sediments. Sediment bioassays with amphipods produced some low survival rates, but these appear to be related to testing sediments with a high silt content rather than any trace chemicals in the sediments, be they natural or anthropogenic in origin. The levels and patterns of induction of CYP1A in cells of bottom-dwelling fish are consistent with some mild induction by contaminants, but with weak induction in the gills they appear not to be waterborne, but rather from the diet. None of the measured contaminants in the fish tissues correlated with CYP1A induction, but chlorinated hydrocarbons were not measured (ADL, 1998:ES-4).

In response to concerns that subsistence food resources are being contaminated, EPA also initiated a pollution study for Cook Inlet in 1997. The study was conducted specifically to provide information to characterize potential human health risks associated with exposure to contaminants detected in subsistence food items harvested from Cook Inlet by members of four Alaskan subsistence villages: Tyonek, Seldovia, Port Graham, and Nanwalek. The study is looking for dioxins, pesticides and PCBs that might enter the Inlet through runoff from urban sources as well as production platforms. The study concentrates on species harvested for subsistence. Sampling was conducted between May and mid-summer 1997. More than 100 samples of subsistence fish, shellfish, and marine plants were tested for dioxins/furans, PAHs, pesticides, PCBs, and metals including inorganic arsenic, barium, cadmium, chromium, methyl mercury, and selenium.

Preliminary results indicate that contaminant levels in fish and plants are some of the lowest ever detected by EPA. Several groups of chemicals (dioxins/furans, Aroclor PCBs, and PAHs) were rarely detected. For almost every contaminant tested for by EPA, concentrations were either completely non-detectable or were below levels of concern. Chemical concentrations for the following species were below levels of potential concern:

Fish	Invertebrates	Plants
Chum Salmon	Mussel	Goose tongue
Sockeye salmon	Butter clam	Kelp
Cod	Large clam	Seaweed
Flounder	Blue mussel	
Halibut	Steamer clam	

Laboratory results showed three contaminants in several food items at concentrations that might pose a health risk to people who eat them. PCBs and traces of mercury were found in sea bass, but "[t]he concentrations of PCB's and methyl mercury are very low relative to what's been found in other studies elsewhere, and are at or below typical background levels." (EPA, 1998c). Cadmium was detected in snails, chitons, and octopus likely attributable to natural glacial deposits. EPA is determining if the cadmium concentrations reflect background concentrations or are elevated due to human activity. Oddly, a pesticide called dieldrin was detected in king salmon. EPA plans to reanalyze the salmon to ensure that initial lab work was accurate (EPA, 1998a). The three contaminants may pose a slight health risk to humans depending on how much is eaten, how often it is consumed, and how the food is prepared (EPA, 1998c).

Preliminary results of the EPA subsistence foods study concur with other pollution studies of Cook Inlet: Contaminant levels (regardless of their source) in sediments and tissues are at background levels or are undetectable, and do not pose a threat to Cook Inlet biota.

In 1998, CIRCAC, at a public meeting in Kenai, AK, presented a synthesis and evaluation of monitoring data from their 1993-97 environmental monitoring program. The summary and conclusions are as follows (LEES, 1998):

Sediment Hydrocarbons -- Sediments exhibit extremely low levels of PAHs (40 to 50 times below Effects Range Low (ERL) concentrations). The sources of these hydrocarbons are varied and mixed, but cannot be directly attributed to Cook Inlet oil and gas development operations. There is no evidence of *Exxon Valdez* Oil Spill oil or Alaska North Slope oil in any of the subtidal sediments sampled, including sediments of Shelikof Strait (LEES, 1998).

Tissue Hydrocarbons -- Subtidal organisms have not accumulated or been exposed to high levels of hydrocarbons from Cook Inlet oil and gas activities. However, minimal exposure of intertidal organisms to petroleum products has occurred in some instances. Mixtures of diesel and very low-level combustion-derived hydrocarbons were noted in Tuxedni Bay, and fresh oil seep signals were possibly observed in Chinitna Bay (LEES, 1998).

Hydrocarbon Sources -- River-borne terrestrial sources of particulate coal may contribute significant levels of PAHs to the sediments throughout the region. Total napthalenes/TPAH ratios tend to increase with sand-sized particles suggesting a particulate coal-derived source for much of the PAHs observed in the sediments. Very few of the low-level PAH signatures for either sediments or tissues could be directly tied to specific sources, and the samples suggest undocumented or multiple sources (LEES, 1998).

Water Column Hydrocarbons -- Tests using blue mussels for detecting PAHs in the water column near produced water outfall pipes did not indicate a presence of PAHs, however, high suspended sediment loads and other factors may have diminished the test's accuracy. Despite technical difficulties, semi-permeable membrane devices did show evidence of a produced water PAH signal in the Trading Bay area and a possible weathered diesel signal in Kachemak Bay. Methods and procedures for determining water column hydrocarbon levels need further development (LEES, 1998).

Results of the 1993-97 CIRCAC Monitoring Program concur with other pollution studies of Cook Inlet: Contaminant levels (regardless of their source) in sediments and tissues are at background levels or are undetectable, and do not pose a threat to Cook Inlet biota.

In response to the stakeholders' process for an earlier Cook Inlet lease sale, the *Exxon Valdez* Oil Spill Trustee Council is funding a watershed data gathering and distribution project at the request of ADNR. Similar projects to develop a watershed data "clearinghouse" have been initiated by USGS, EPA, and others. Internet web sites provide a new medium to obtain and distribute water quality data.

b. National Pollution Discharge Elimination System (NPDES)

The federal Clean Water Act established the National Pollutant Discharge Elimination System (NPDES) to permit discharges of pollutants into U.S. waters by "point sources," such as industrial and municipal facilities (ADEC, 1997b). This EPA and ADEC program regulates the effluent discharge of point-source pollution into the nation's waters and insures that both state and federal water quality standards are met. Once approved, the federal permit is certified by ADEC.

The original 1986 permit for Cook Inlet expired in 1991 and a new permit has been drafted, reviewed, and awaits finalization by EPA. In 1995, the Alaska DGC issued a determination that the draft permit was consistent with the ACMP and KPB Coastal Management Program, but that was challenged in court. The new general NPDES permit for Cook Inlet is expected to be reissued in February (EPA, 1998b).

NPDES permits establish effluent limitations, standards, prohibitions and other conditions on discharges from facilities in the general permit area. These conditions are based on the administrative record. EPA regulations and the permit contain a procedure for owners or operators to apply for an individual permit. A total of 23 facilities were covered under the previous general permit. A description of the basis for the conditions and requirements of the proposed permit is given in the fact sheet published in the Federal Register on September 20, 1995 (EPA, 1995b).

Effluent limitations and monitoring requirements for discharges are explained in detail in the NPDES General Permit. The permit contains information about the type of pollutant being discharged, its source, and quantity. Effluent guidelines in place prohibit the release of oil and limit the discharge of cadmium, barite and mercury in drilling fluid emissions. Several different types of discharges are classified (see Table 5.2) (EPA, 1995b).

Pollutants monitored include biological oxygen demand (BOD), fecal coliforms, pH, total suspended solids, and oil and grease. Toxic pollutants include heavy metals like lead, copper and arsenic, and organic chemicals like benzene, naphthalene and more than 120 others. Anything not listed as conventional or toxic are non-conventional pollutants (EPA, 1995a). Monitoring results are available to the general public by contacting EPA.

When the NPDES permit is reissued, discharges from existing facilities in state waters north of the Forelands are re-authorized. Discharges are also authorized from exploratory facilities in all state and federal waters of Cook Inlet (north of a line from Cape Douglas to Port Chatham). Discharges must comply with effluent limitations, monitoring and reporting requirements, and other conditions set forth in the permit. The permit does not authorize discharges from "new sources" as defined in 40 C.F.R. §122.2 (EPA, 1995b)(EPA, 1998b).

Table 5.2 Types of discharges that are authorized under the NPDES General Permit:

Drilling Mud and Cuttings	Deck Drainages
Sanitary Wastes	Domestic Wastes
Desalination Unit Wastes	Blowout Preventor Fluid
Boiler Blowdown	Fire Control System Test Water
Non-Contact Cooling Water	Uncontaminated Ballast Water
Bilge Water	Excess Cement Slurry
Mud, Cuttings, Cement at Sea floor	Waterflood Discharges
Produced Water	Completion Fluids
Work-over Fluids	Well Treatment Fluids
Test Fluids	

From EPA, 1995b.

The general NPDES permit may be modified or revoked at any time if, on the basis of new data, the EPA Director determines that the new information would have affected the application of conditions in the permit. In addition, the permit shall be modified or revoked if, on the basis of new data, the EPA Director determines that continued discharges may cause unreasonable degradation of the marine environment. (EPA, 1995b).

Prohibited areas of discharge are defined in the Cook Inlet General NPDES permit. Some restrictions include:

- Intertidal areas: The discharge of produced water from new facilities is prohibited in intertidal areas. New discharges (as defined in 40 C.F.R. § 122.2) are also prohibited from discharging produced water shoreward of the 10-meter isobath (as measured from mean lower low water).
- Nearshore areas: All discharges are prohibited shoreward of the 5.5 meter isobath adjacent to either the Clam Gulch Critical Habitat Area or from the Crescent River northward to a point one-half mile north of Redoubt Point.
- Special areas: All discharges are prohibited within the boundaries or within 1,000 meters of a coastal marsh, river delta, river mouth, designated Area Meriting Special Attention (AMSA), game refuge, game sanctuary, or critical habitat area. This restriction applies to Susitna Flats SGR, McNeil River SGS, Redoubt Bay CHA, Trading Bay SGR, Kalgin Island CHA, Clam Gulch CHA, Kachemak Bay CHA, and the Anchorage Coastal Wildlife Refuge.
- All discharges are prohibited in Kamishak Bay west of a line from Cape Douglas to Chinitna Point and in Chinitna and Tuxedni Bays.
- (From: EPA, 1998b)

3. Surface and Groundwater Quality

This section will describe the sources of groundwater contamination in the area considered in this finding, and analyze the potential for current oil and gas activities to affect water quality. For a description of general hydrology and aquifer dynamics of the area considered in this finding, see Chapter Two.

a. Existing Soil and Groundwater Quality

Water quality throughout the Cook Inlet area varies seasonally with changes associated with streamflow. Peak runoff occurs from late May to early July during and after break-up, and elevated turbidity and suspended sediment levels are common during these months. Natural as well as man-made contaminants can result in exceedences of water quality criteria. Natural contaminants to fresh water supplies include dead fish, birds, and animals; mosquito and insect larvae; algae and other plants; bacteria; parasites such as Giardia; silt and glacial flour; arsenic, iron, manganese; and hydrogen sulfide gas (AEIDC, 1974).

Water quality data are site-specific and often project-generated in the Cook Inlet basin. Generally, spring water or groundwater is good throughout the Kenai Peninsula area, with the exception of some supplies noted for high iron and sulfate (Waller, 1968)(Freethy and Scully, 1980)(Glass, 1995).

Groundwater in the Matanuska-Susitna Valley has a greater chemical quality variability than surface water. Groundwater is generally harder than surface water, except in areas adjacent to streams. Objectionable quantities of iron are common in shallow wells (Jokela, et al., 1990; citing to Feulner, 1971). Overall, groundwater in the Mat-Su Valley is suitable for domestic, agricultural, and commercial or industrial use. A few specific waste-disposal operations have caused local groundwater impairment. In the Houston area, groundwater quality is generally of good quality with some exceptions. Some wells near the town center produce water of low quality with a ‘rotten egg’ odor characteristic of the presence of hydrogen sulfide. Water samples from one well contained high levels of sodium and orthophosphate, and low levels of calcium and sulfate (Maynard, 1987:4). Palmer area groundwater is also good, requiring little or no treatment. Some water in wells contain a high iron content, and LaSage (1992) reports that at least one well contained gas when initially drilled (LaSage, 1992:9). Many public wells would not meet the water quality standard for iron (<0.3 mg/L) without using water-conditioning equipment (Maynard, 1987).

“High concentrations of manganese and iron in ground water are common in Anchorage.” (Glass, 1986b:14). Anchorage has experienced local groundwater contamination by the disposal of solid waste directly into lakes that are connected to the groundwater system, or by surface disposal in landfills where the water table is shallow. Aquifer contamination occurs at Peters Creek where concentrations of benzene and xylene were detected in wells due to a leaking underground gasoline storage tank nearby. Shallow groundwater beneath Merrill Field landfill and the Greater Anchorage Borough landfill (closed in 1977) is severely contaminated with leachate produced within the refuse (USGS, 1986). Natural contaminants also can be found in Anchorage groundwater. “In some locations [of the Connors Bog area], natural concentrations of iron and manganese and a yellow-brown color make unconfined ground water unsuitable for most uses without treatment.” (Glass, 1986a:11).

Man-made sources of surface and groundwater contamination include refined petroleum products, industrial wastes, landfill or dump leachate, and septic system discharge. Salt-water intrusion due to pumping may also contaminate groundwater supplies where wells are near the ocean. For a description of groundwater occurrence, see Chapter Two.

ADEC maintains a list of contaminated sites in Alaska. Most contaminated sites in Alaska are associated with leaking underground storage tanks from gas stations and leachate from old landfills. A list of all leaking underground storage tanks (USTs) in Alaska can be obtained from the ADEC web site (http://www.state.ak.us/dec/dspar/stp/lust.htm). Numerous (855) leaking underground storage tank sites exist in the sale area and about half of these are considered “closed” by ADEC (Petrick, 1998). Thus there is benzene in soils and in some water tables, with some exceeding state water quality standards for drinking water.

Pollution sources (all sources) include defense sites, old landfills, airports, auto and truck repair shops, industrial storage yards, energy facilities, field camps, construction yards, salvage yards, oil storage facilities, communications facilities, and abandoned drums containing industrial by-products. Industrial pollutants include gas condensates, batteries, waste oil, lead, barium, chromium, arsenic, formaldehyde, hydrochloric acid, chlorinated and non-chlorinated solvents, benzene, toluene, ethylbenzene, xylene, halogenated volatile organics, and polychlorinated biphenals (PCB’s), industrial process chemicals and resins, septic tank wastes, grease, gasoline, diesel, home heating fuel, aviation fuel, and unknown substances. Sites which pose a threat to human health have remediation working plans. At many sites, contaminants have reached the water table, while at others, the pollutants were cleaned up or have not penetrated soils. Limited documentation is available on quantity released, plume flow, or downstream effects on habitats, fish, and wildlife. Volumes spilled range from unknown (oily saturated soil) to nearly 400,000 gallons of oily wastewater that leaked from the Tesoro refinery (Petrick, 1998).

ADEC, Division of Spill Prevention and Response maintains a contaminated site database. There are six categories in the database:

- UC = Unconfirmed: sites that are suspected of being contaminated but have no data to confirm that a release occurred.
- AC = Active: sites with confirmed contaminant releases that are actively being worked through a remedial process.
- IN = Inactive: sites with confirmed contaminant releases which are not being actively worked through a remedial process.
- CL = Closed: sites that have completed a remedial process, have been determined to pose no further threat to human health or the environment.
- NA = No Further Action: sites regulated under the federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) which have met guidelines established by the Act.
- IC = Institutional Control: sites that have been remediated in situ but require monitoring to ensure no further exposure or threat will be made to human health and environment.

Modern contamination is attributed to human error, although abandoned drums are occasionally discovered, reported to ADEC, and added to the list. For many of the sites, the original polluter or operator is absent, and the current land owner is responsible for site remediation. Contaminated sites are ranked by ADEC for cleanup based on threat to human health. Those sites that pose the most immediate threat have been evaluated and characterized in terms of volume and type of contaminant spilled. Most contaminated sites that are located near existing oilfield infrastructure are attributable to oil and gas operations (Petrick, 1998)(ADEC, 1993).

Some surface waterbodies in the sale area are stressed by pollution or suspected of being contaminated. ADEC maintains a list of waters contaminated or suspected of being contaminated. ADEC prepares this list biannually under Section 303(d) of the Clean Water Act in order to prioritize clean-up efforts. Impaired or suspected of being impaired waterbodies in the sale area include Cheney Lake, Little Rabbit Creek, Little Survival Creek, Ship Creek (Glenn Hwy bridge to mouth), Fish Creek, Furrow Creek, Campbell Creek, Campbell lake, Chester Creek, Eagle River Flats, Lake Hood, Lake Spenard, Little Campbell Creek; University Lake, Westchester Lagoon, and Jewel Lake in Anchorage and Lake Lucille in Wasilla. Fecal coliform bacteria is the most common pollutant source (ADEC, 1998). Waterbodies that are Section 303(d) listed may have total maximum daily load (TMDL) discharge limits for the purposed of maintaining state water quality standards. Consideration of stressed waterbodies may be relevant in permit decision making if operations or facilities are proposed in or upstream of these stressed systems.

ADEC maintains an impaired groundwater database in Juneau. In 1992, there were approximately 1,300 sites identified statewide in the database and groundwater contamination has been detected at approximately 180 of those, including military installations (ADEC, 1992:36). Groundwater resources are contaminated at industrial facilities at Nikiski and Kenai and at sites in Sterling, Soldotna, Anchor Point, and Homer (Munter & Maynard, 1987:6). Nearly 60 percent of the cases of impaired groundwater in the database are a result of failed underground storage tanks. Fourteen percent are attributed to bulk fuel and above ground storage facilities, and 12 percent are attributed to solid waste facilities and abandoned hazardous waste sites (ADEC 1992).

Some contaminated aquifers in the sale area are in the process of being treated by responsible parties. Clean-up or remediation options for contaminated soils and groundwater are changing as new technologies and methods are tested. Usually, the responsible party will meet with ADEC and EPA to determine what action, if any is optimal. Monitoring wells are drilled to determine the extent and flow characteristics of the contamination plume. Options for remediation, such as those used by the U.S. military include pumping and treating, high-vacuum extraction, air sparging, intrinsic remediation, excavation, composting, thermal treatment, bioventing, and debris removal and backfilling. Often a combination of remediation alternatives is used.

Water quality guidelines for public drinking water are generated by the EPA under the Clean Water Act and by the ADEC under AS 46.03. The EPA sets national standards for maximum constituent levels (MCL's) in drinking water and state standards are enforced by ADEC. A Certificate of Reasonable Assurance (Water Quality Certification) is required under 18 AAC 15 in order to protect the waters of the state from being polluted and assures that the issuance of a Federal Permit will not conflict with Alaska's Water Quality Standards.

Communities without public wastewater systems may experience water quality problems associated with organic contaminants, like fecal coliform bacteria. The EPA requires water quality monitoring for all public water supplies (USGS, 1986).

Selected water-quality constituents and their environmental significance

Fecal coliform bacteria: *human and animal waste*.

Alkalinity: *high levels unsuitable for agriculture and industry uses*.

Sulfate*: may harm aquatic organisms/unsuitable for public supplies.*

Dissolved solids: *may harm aquatic organisms/unsuitable for public supplies.*

Nitrate plus nitrite: *can cause algal blooms/unsuitable for public supplies.*

Barium: *toxic in larger concentrations*.

Suspended sediment*: harms some aquatic animals/can fill reservoirs and impact recreation.*

Source: The Water Quality Encyclopedia. Van der Leeden, Fritz. Lewis Publishers, 1990

b. Cumulative Effects on Surface and Groundwater

Potential effects that may alter surface water quality parameters include accidental spills of fuel, lubricants or chemicals; increases in erosion and sedimentation causing elevated turbidity and suspended solids concentrations; and oil spills. Industry's activities may alter water quality characteristics including pH, total suspended solids, organic matter, calcium, magnesium, sodium, iron, nitrates, chlorine, and fluoride. (Parametrix, 1996).

The extent and duration of water quality degradation resulting from accidental spills depends on the type of product; the location of the spill; volume; season and duration of the spill or leak; and the effectiveness of clean-up response. Heavy equipment, such as trucks, tracked vehicles, aircraft, and tank trucks commonly use diesel fuel, gasoline, jet fuel, motor oil, hydraulic fluid, antifreeze, and other lubricants. Spills or leaks could result from accidents, such as during refueling, or from corrosion of lines (Parametrix, 1996). Under standard ADNR permit conditions for off-road activity, fuel and hazardous substances must have secondary containment apparatus. A secondary containment or surface liner must be placed under all container or vehicle fuel tank inlet and outlet points. Appropriate spill response equipment must be on hand during any transfer or handling of fuel or hazardous substances. Vehicle refueling is prohibited within the annual floodplain or tidelands (ADGC, 1995). Oil spills are discussed in Chapter Five.

Surface waterbodies could be impaired by the discharge of hazardous substances or by displacing soil via road building or gravel mining (increasing turbidity and siltation, thereby altering water quality and exceeding Alaska Water Quality Standards). ADEC prepares a list of impaired waterbodies in Alaska. Nearly half of the impaired waterbodies are a result of urban storm runoff (ADEC, 1998)

Standard ADNR land use permit conditions on facility construction and operation ensure water quality is not degraded. Trails, campsites and work areas must be kept clean. Trash, survey markers, and other debris that may accumulate in camps or along seismic lines and travel routes that are not recovered during the initial cleanup must be picked up and properly disposed of. All solid wastes, including incinerator residue must be backhauled to a solid waste disposal site approved by ADEC. Vehicle maintenance, campsites, and the storage or stockpiling of material on the surface of lakes, ponds, or rivers are prohibited (ADGC, 1995).

ADEC issues industrial and municipal wastewater permits, and monitors wastewater discharges and the water quality of waterbodies receiving the discharges. ADEC certifies federal wastewater permits with mixing zones that allow industrial and municipal facilities to meet state water quality standards. Industrial and municipal wastewater facilities are inspected annually. ADEC also certifies U.S. Army Corps of Engineer dredge and fill permits in wetlands and navigable waters to ensure compliance with state water quality standards, and provides technical assistance for design, installation, and operation of industrial and municipal wastewater systems (ADEC, 1997b).

Geophysical exploration within the Cook Inlet and Susitna areas with low-pressure ground vehicles is not expected to alter water quality because seismic surveys are normally conducted in winter and permit conditions mitigate potential damage. Equipment, other than vessels must not enter open water areas of a watercourse during winter, and any ice roads, ice bridges, or approach ramps constructed near river, slough, or stream crossings must be free of extraneous material before break-up. Alterations of the banks of a watercourse are prohibited (ADGC, 1995). Adherence to these conditions thus avoids or minimizes post-seismic increases in erosion, turbidity, and suspended solids in a drainage area.

ADNR geophysical exploration permits include stipulations to avoid disrupting local well water supplies. Measures may also be attached in order for activities to be consistent with the ACMP and local district plans. For example, permit stipulations include setbacks for lakes and rivers. Permit applicants must seek permission from landowners to enter private property. One operator on the Kenai Peninsula required a 500-foot minimum setback distance between explosive charges and wells and building foundations to prevent shallow aquifer damage.

i. Surface Disposal of Drilling Waste

Until regulatory reforms of the 1980s, it was common practice to discharge waste onto the ground. Also, in past years, there was no market for gas condensate, and the thick sludge by-product of production drilling was placed in pits. In the past, an unlined reserve pit was used to facilitate drilling. Drilling fluids were pumped down the well casing, through the bit, and the fluid along with solids (cuttings) returned to the surface via the annulus where it was then placed into a settling system in the open reserve pit. The solids settled to the bottom, and the fluids were reclaimed and reused in the drilling process. In the past, these solids were left in the unlined pit. Such pits are in the process of being cleaned up under ADEC's solid waste program. ADEC contacts the owner or operator or driller, a site evaluation is made, and a cleanup work plan is developed with the goal of eventually closing the reserve pit. Many of the old reserve pits are closed-out (Peterson, 1998).

Modern reserve pits are called drilling waste mono-fills and are permitted by ADEC under 18 AAC 60. Temporary storage of drilling wastes is permitted under these regulations. Drilling solids are placed into a lined pit, which is capped and soil placed on top. These containment cells require groundwater monitoring wells and a long-term groundwater monitoring program. They are very expensive and carry a significant liability for the company, thus it is not the preferred method of disposal. Less expensive alternatives for drilling waste disposal are reinjection into an approved injection well or down the well annulus (20 AAC 25.080) and shipment of wastes to an approved disposal or incineration facility. Drilling muds, fluids, and wastes may also be transported by barge, tanker truck, or a combination of the two, depending on the project, and shipped off-site for proper disposal. Cuttings are crushed in a milling process and either reinjected thousands of feet below the surface or disposed of in an approved solid waste cell with an impermeable lining. Muds and cuttings may be transported.

Wastewater Disposal Permits are required by ADEC for proper disposal of fluids including gray water from worker housing facilities (18 AAC 72). Title 18 AAC 60.220-400 requires a Solid Waste Disposal Permit to operate a solid waste disposal facility or to control or eliminate detrimental health, environmental, and nuisance effects of improper solid waste disposal practices. Drilling waste disposal facilities must comply with Solid Waste Disposal regulations (18 AAC 60.200-400). Under this chapter, drilling waste includes muds, cuttings, hydrocarbons, brine, acid, sand, and emulsions or mixture of fluids (18 AAC 60.990(41)). Drilling waste disposal facilities must also comply with storage, operating, design, and monitoring requirements as defined in 18 AAC 60.430-440. Under 18 AAC 60.430(c), drilling waste disposal facilities must be designed to take into account the location of the seasonal high groundwater table, surface water, and continuous permafrost, as well as proximity to human population and to public water systems, with the goal of avoiding any adverse effect on such resources. Under 18 AAC 60.430(d), liners must be designed and installed to assure that they will remain in place during the active life of the facility and any post-closure care period, and will prevent drilling waste or leachate from escaping.

ii. Injection of Drilling Waste

Injection is the subsurface emplacement of fluids in a well. A “fluid” is any material that flows or moves, whether it is semisolid, liquid, sludge, and gas. In response to concerns that subsurface disposal of wastes could pollute underground sources of drinking water, the Underground Injection Control (UIC) program was founded under the Safe Drinking Water Act of 1974. In Alaska, the UIC program is administered by the AOGCC. All disposal wells are deep beneath any drinking water aquifer. See figure 5.2

Potential for contaminating groundwater depends on several factors: where the injection occurs relative to the aquifer; well construction, design, and operation; injectate quality; and volumes of waste injected. “The operator has the burden of demonstrating that the proposed disposal or storage operation will not allow the movement of fluid into sources of freshwater. Disposal or storage wells must be cased and the casing cemented in a manner that will protect oil, gas, and freshwater sources.” 20 AAC 25.252(b).

Under the UIC program, there are five classes of injection wells. Class II wells are used to inject fluids associated with oil and natural gas production or enhanced hydrocarbon recovery. These wells inject below the lowermost underground source of drinking water, except in cases where the aquifer is hydrocarbon producing. In the Cook Inlet basin, oil production wells are usually 10,000 to 15,000 ft deep and gas wells, 3,000 to 8,000 ft. (Glass, 1995:16-17). The deepest drinking water well in the sale area is about 500 feet (Ireland, 1995).

Under 40 C.F.R. §146.4, a freshwater aquifer may be exempt from the casing, drilling and cementing requirements if it is currently not serving as a source of drinking water, cannot be used in the future as a source, or because it is too deep, or otherwise unfit for human consumption. In the Cook Inlet basin, exempt aquifers include those within one-quarter mile of the well and below a depth of 1,300 feet for the Kenai Gas Field, 1,650 feet for the Beaver Creek Field, and 1,700 feet for the Swanson River Field. Other aquifers are exempt beneath the gas fields of Granite Point, Middle Ground Shoal, McArthur River, and Trading Bay (AOGCC, 1998).

As of February 1998, there were 16 Class II waste disposal wells in the Cook Inlet basin: five in the Swanson River field, three in the Beaver Creek field, two in the Kenai field, and two in the Middle Ground Shoal field. Additionally, Beluga River, Lewis River, Trading Bay, and West McArthur River fields each have one disposal well. The shallowest waste disposal well in the Cook Inlet basin is 2,461 ft (total vertical depth), where fluids are injected at the Swanson River Unit. Most injection wells in Cook Inlet are drilled deeper than 8,000 ft. total vertical depth (AOGCC, 1998).

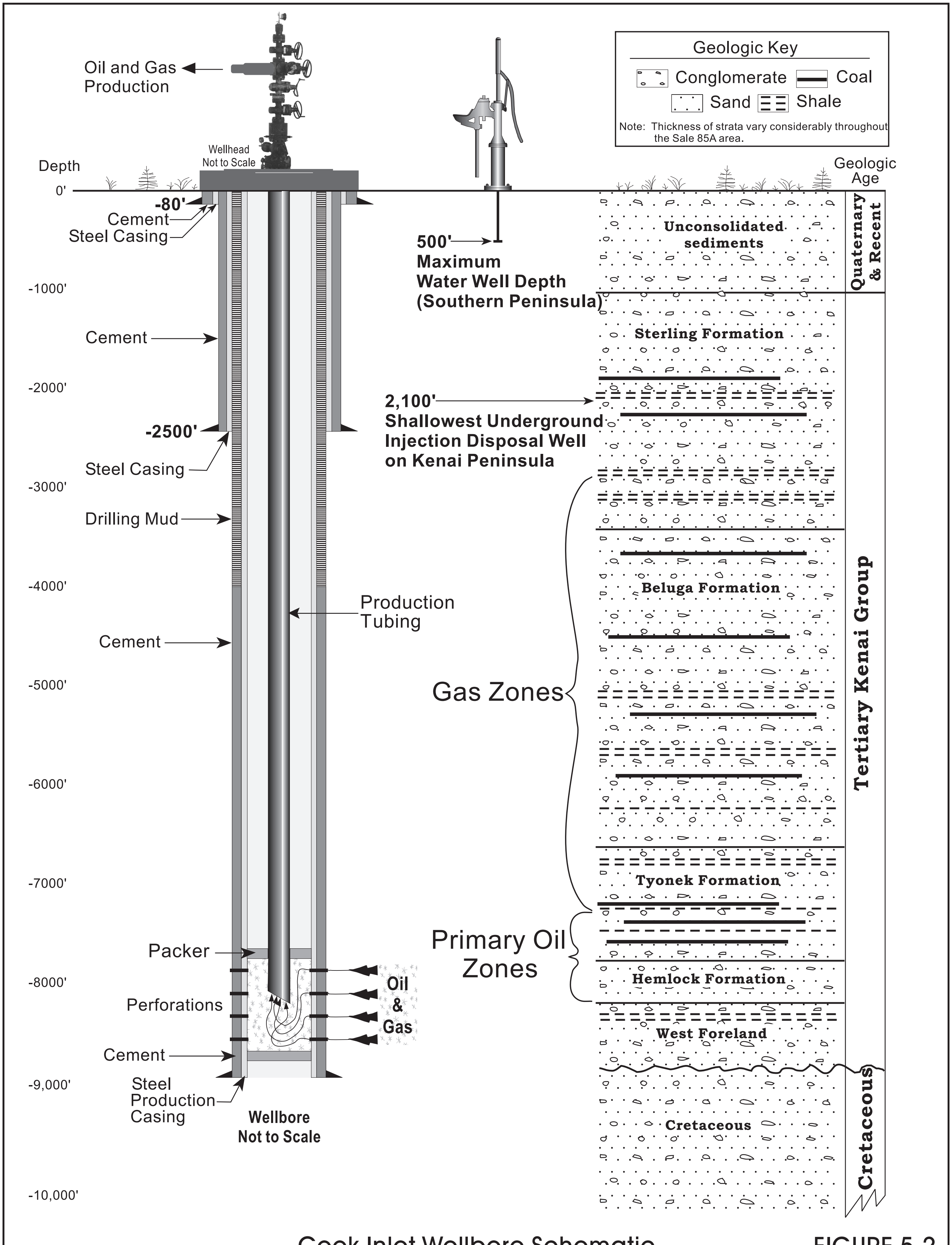
Under abnormal circumstances, improperly injected fluids could escape from or pass through from one stratum to another and pollute a groundwater aquifer. Considering the density, composition, thickness, and porosity of the Kenai Group strata, it is unlikely that injected fluids could migrate to any known drinking water aquifers. It would likely take several thousand years for such a migration to occur and the risk to drinking water supplies is therefore low. It is possible, however, that drilling fluid could percolate up a fissure in the earth and enter an aquifer or other surface waterbody. The same process brings oil, gas, and water to the surface as natural seeps (Kornbrath, 1996).

The AOGCC reviews each drilling proposal to ensure proper well design, well control equipment, hydrogen sulfide detection equipment, well logging, production practices, plugging and abandonment procedures, and to check for shallow geophysical hazards and over-pressure zones. The Commission also regulates well spacing, disposal of salt water and oil field waste, completion techniques, gas-oil-water ratios, pressure maintenance efforts, mud systems, diverters, blow-out prevention equipment, and the construction, cementing and setting depth of casings and tubing (AOGCC, 1996). Annular disposal of drilling fluids is regulated by AOGCC under 20 AAC 25.080.

Materials and fluid derived from the drilling of the wellbore may be injected into a well annulus (the space between the mud cake and the well casing), and an Annular Injection Permit is required. The AOGCC considers the volume, depth, and physical and chemical characteristics of the sub-terrainean formation that will receive the fluid. The operator must demonstrate that the proposed disposal or storage operation will not allow the movement of fluid into sources of freshwater and must produce evidence and data to support a Commission finding that the proposed disposal or storage will not initiate or propagate fractures through the confining zones and possibly enter a freshwater strata (20 AAC 25.252).

Under the UIC program (20 AAC 25.030(a)), the Commission verifies the mechanical integrity of injection wells, determines appropriate injection zones and overlying confining strata, and determines the presence or absence of fresh water aquifers and ensures their protection. Verification that approved procedures and practices are followed is done by field inspection, and quarterly reports of in-house and field monitoring are prepared for the EPA (AOGCC, 1996). All offshore and onshore wells must have surface casing set "below the base of all water-bearing strata known or reasonably expected to serve as a source of drinking water and below the base of permafrost, at a depth that will insure good anchorage to prevent blowouts or uncontrolled flow." (20 AAC 25.030(d)(2)(A)). All casing strings must be pressure tested for leaks, both initially and during the life of the well if injection occurs (20 AAC 25.030(g)). Under AS 31.05 and 20 AAC 25, the AOGCC issues a Permit to Drill, requiring a $100,000 bond for a single well or a $200,000 bond if more than one well is to be drilled.

Well casings could be ruptured by an earthquake or severed by a slipped fault. Rupture could also occur if the casing is constructed improperly, such as from an inadequate cementing technique. This kind of underground contamination is unlikely. Under 20 AAC 25.265, all oil and gas wells which are capable of unassisted flow (under pressure) of hydrocarbons must be equipped with both surface and subsurface safety systems to prevent uncontrolled flow. If a well were to be severed, there would be an immediate pressure differential, which would trigger the automatic shut-off valves. No case of earthquake damage to an oil or gas well in Alaska is known to DO&G or AOGCC (Mahan, 1996a). See Chapter Eight for more information on governmental powers to regulate oil and gas activities.



Cook Inlet Wellbore Schematic

FIGURE 5.2

Drawdown of Domestic Water Tables

Industrial use of water can affect nearby domestic well water depths. Industrial pumping can draw down the elevation of the water table in the vicinity of the industrial well or wells. Pumping from a well or closely spaced group of wells creates a cone of depression in the water level of an unconfined aquifer (see Chapter Two for a description of known sale area aquifers). Often this decline is insignificant and temporary as other hydraulically connected groundwater sources replace pumped volume. In streams that are hydraulically connected to groundwater systems, industrial pumping may cause a reduction in surface flow or alteration of drainage pattern. This disruption in stream flow may be more pronounced during winter months when surface-flow is minimal (Zenone and Anderson, 1978:19).

In the Nikiski area, between 1968 and 1979, total consumption of groundwater by wells of different depths more than quadrupled to 4.2 million gallons per day, primarily due to the demands of the Phillip's Petroleum Kenai Plant and the Tesoro Alaska refinery. Area lake levels declined by as much as eight feet since industrial pumping began, however researchers noted that drawdowns in each aquifer had stabilized (Nelson, 1981).

Declines in lake levels are also associated with fluctuations in precipitation and it is difficult to separate out effects of industrial pumping (Nelson, 1981:19). Most domestic wells on the Kenai Peninsula tap an upper unconfined aquifer, but water can be found at much greater depths (Nelson, 1981)(Ireland, 1995). Permits may contain stipulations on the use and quantity drawn of water in order to protect recreation activities, navigation, water rights or any other substantial public interest. Water use permits may also be subject to conditions, including suspension and termination of exploration activities, in order to protect fish and wildlife habitat, the public health or to protect the water rights of other persons. Before a permit to appropriate water is issued, ADNR considers local demand and may require applicants to conduct aquifer yield studies. Generally, water table declines associated with the upper unconfined aquifer can be best mitigated by industrial users tapping confined (lower) layers or searching for alternate water sources. As noted in Chapter Two, water yields necessary for industrial purposes are generally not available in the shallower aquifers where most residents derive well water.

The use of water for industrial purposes is regulated by ADNR and ADEC. Information on local ground and surface water withdrawals can be obtained by contacting ADNR Division of Mining and Water Management.

4. Summary

Byproducts of drilling consist of muds, cuttings, and produced waters. These wastes are either reinjected into the subsurface below any drinking water aquifer as a preferred method or treated and either disposed of in an approved solid waste cell onshore, transported out of state, or discharged into Cook Inlet under the NPDES permit. Wastewater from work modules, gravel pads, and production platforms also must be treated and controlled, so as to protect water quality. See Chapter Eight for more information on governmental powers to regulate oil and gas activities. See also Chapter Two for more information on sale area water resources.

Currently, all offshore discharges are monitored and controlled by the NPDES permit system, jointly administered by EPA and ADEC. Due to the dynamic physical system of Cook Inlet, and the mostly natural composition of drilling fluids, their discharge has not significantly degraded marine water quality of Cook Inlet. A federally mandated monitoring program and other independent studies continue to search the Inlet for the presence of hydrocarbons and metals in marine water, sediments, and marine species. Levels of hydrocarbons and metals in Cook Inlet are at detection or background levels, and sources other than oil and gas industry sources .

In the past, improper waste disposal practices have contributed to surface and groundwater contamination. Knowledge and understanding about groundwater and contaminants was not widespread and current land and water resource protection measures were not in place. Oil and gas industrial wastes along with domestic, commercial, and municipal wastes were placed in reserve pits and subsequently, contaminants leached into the water table. Since then, oil and gas waste disposal methods have improved dramatically. Industry waste disposal is regulated specifically by state and federal programs to insure proper treatment, handling, storage, and disposal. Failure to follow regulation guidelines can lead to fines and penalties.

Regulatory programs and current industry practices also prevent freshwater aquifer contamination or depletion from industrial water use. Oil and gas production and injection wells are made with cement and steel casings, which prevent undesired flow into nearby stratum. Zones where fluids are injected are thousands of feet below the deepest drinking water aquifers. Geological hazard surveys of faults are required prior to drilling, minimizing the potential for a contaminant to migrate into a drinking water source. During drilling, non-toxic fluids must be used until all drinking water aquifers have been passed and protective casing is in place. The potential for aquifer contamination resulting from a cracked or ruptured well casing exists, but is very unlikely given oil and gas well construction methods, materials, and safety systems.

Despite improved methods, practices, and technology, the potential for contamination of surface or groundwater resources from improper handling or disposal of drilling fluids continues to exist. However, a combination of agency and citizen oversight, lease mitigation measures, project-specific permit stipulations, and existing statutes and regulations make this potential unlikely.

Information on aquifer contamination, such as volume and quantity of pollutants spilled, soil characteristics, contaminant plume flow modeling, and status of recovery efforts may be relevant in permit decision making where operations or facilities are proposed at contaminated site locations. Post-sale facilities and operations are expected to have little or no impact on existing groundwater contamination or ongoing clean-up efforts.

In addition to permit requirements, statutes, and regulations described in the sections above, mitigation measures and lessee advisories have been developed as part of the Cook inlet Areawide Sale process and will be applied to all leases.

Mitigation Measures

Several mitigation measures and lessee advisories serve to protect water quality from post-sale oil and gas activities. The following are summaries of some applicable mitigation measures. For a complete, full text listing of mitigation measures see Chapter Nine. Measures and advisories that would mitigate potential impacts to water quality are:

- Wetland and Riparian Protection -- Lessees must avoid siting facilities in key wetlands and identified sensitive habitat areas. Onshore facilities other docks, or road and pipeline crossings, will not be sited within 500 feet of fishbearing streams. Permanent facility siting is prohibited within one-half mile of the banks of Harriet, Alexander, Lake, Deep and Stariski creeks, and the Drift, Big, Kustatan, McArthur, Chuitna, Theodore, Beluga, Susitna, Little Susitna, Kenai, Kasilof, Ninilchik and Anchor rivers. Alteration of riverbanks is prohibited. Operation of equipment within riparian habitats will be prohibited and the operation of equipment, excluding boats, in open water areas of rivers and streams will be prohibited.

- Water Conservation -- Removal of water from fishbearing rivers, streams, and natural lakes shall be subject to prior written approval by DMWM and ADF&G.

- Turbidity Reduction -- Gravel mining within an active floodplain is prohibited. Gravel mining sites will be restricted to the minimum necessary to develop the field efficiently and with minimal environmental damage, and must not be located within an active floodplain of a watercourse.

- Drinking Water Protection -- a fresh water aquifer monitoring well with quarterly water quality monitoring should be required down gradient of a permanent storage facility unless alternative acceptable technology is approved by ADEC. Coastal districts may require a minimum 500-foot setback distance between explosive charges and wells and building foundations to prevent shallow aquifer damage.

- Drilling Waste -- Underground injection of drilling muds and cuttings is preferred method of disposal. For onshore development, produced waters can only be injected or discharged into Cook Inlet via a NPDES permit approved by EPA. Surface discharge of drilling wastes into waterbodies and wetlands is prohibited. Surface discharge of drilling muds and cuttings into reserve pits is allowed only when it is determined that underground injection is not technically achievable or environmentally preferred. All solid waste disposals require permit approval from ADEC. If use of a reserve pit is proposed, the operator must demonstrate the advantages of a reserve pit over other disposal methods, and describe methods to be employed to reduce the disposed volume. Sumps and reserve pits must be impermeable and otherwise fully contained through diking or other means.

  Disposal of produced waters to freshwater bodies, intertidal areas, and estuarine waters is prohibited. Unless authorized by NPDES and/or state permit, disposal of wastewater into freshwater bodies, intertidal areas, or estuarine waters is prohibited.

- Oil Spill Prevention and Control -- Lessees are advised they must prepare contingency plans addressing prevention, detection, and cleanup of oil spills. Lessees must include in their oil spill contingency plans methods for detecting, responding to, and controlling blowouts; the location and identification of oil spill cleanup equipment; the location and availability of suitable alternative drilling equipment; and a plan of operations to mobilize and drill a relief well. Pipelines must be designed and located to facilitate cleanup. Buffer zones of not less than 500 feet will be required to separate onshore oil storage facilities (with a capacity greater than 660 gallons) and sewage ponds from freshwater supplies, streams, and lakes and key wetlands. Impermeable lining and diking, or equivalent measures such as double-walled tanks, will be required for large onshore oil storage facilities and for sewage ponds. Pipelines, flowlines, and gathering lines must be designed and constructed to assure integrity against climatic conditions, tides and currents, and other geophysical hazards.

- Additional site and area-specific protections are afforded to state game refuges, critical habitat areas, special management areas, special rivers and sensitive habitats. These include prohibitions on surface-entry, restrictions on facility siting, and other restrictions on exploration and construction operations. Operations may be restricted during portions of the year when migrating fish or birds utilize important habitats. Activities in special areas must be consistent with management plans. For more detail on special area protection measures, see Chapter Nine.

E. Commercial Fishing, Recreation and Tourism, and Scenic resources

1. Commercial Fishing

This section describes commercial salmon fishing areas in Cook Inlet, and potential conflicts between fish harvesting and oil and gas industry activities in the sale area. Central to this concern is the tightly controlled commercial fishing "corridor" and the need for coordination between various users of the Cook Inlet waterway.

a. Cook Inlet Fishing Corridor

The harvest of salmon by drift (mobile) and set (fixed) gillnets is highly regulated and fast paced. During intense salmon fishery openers, drift and set gillnet harvesters maneuvering for positions along a tightly controlled boundary attempt to maximize their catch.

In order to avoid trapping fish bound for upper Cook Inlet streams, commercial set and gillnet fishing has historically been restricted to within three miles of the mean high tide mark of the Kenai Peninsula shoreline between Ninilchik and Collier's Dock (KPBPC, 1994:9);(Trasky, 1995:5). Recently, the drift corridor has been identified by latitude and longitude way-points (Ruesch, 1998). The drift and set gillnet corridors in addition to fishing districts, sub-districts, and sections are defined under 5 AAC 21. Portions of the corridor may be closed during salmon runs depending on whether escapement or other management goals have been reached. Sites experiencing heavy use by fishers include Humpy Point (Cape Kasilof) and The Sisters (KPBPC, 1994:11). The best drift net fishing is reported to be on the offshore edge of the corridor (Ruesch, 1996). Sometimes a larger portion of the sockeye run will remain offshore before heading up river, allowing the drift fleet to catch more than expected (ADN, 1993).

According to ADF&G, the three-mile corridor was established because there are no tidal rips in this area, and specific stocks are present in the corridor (KPBPC, 1994:10-11). Drift net fishermen are restricted from the main body of the inlet (beyond three miles), on days other than Mondays and Fridays, to prevent inadvertent harvest of salmon headed for upper inlet streams. Set nets are restricted to 1.5 miles from shore (KPBPC, 1994:11). Drift net operators have a natural advantage of mobility, while set nets are fixed. Drift nets are 900 feet long, 45 meshes deep and are reeled and unreeled from vessels averaging about 30 to 35 feet in length. Set nets are a maximum of 210 feet long and are operated from shore (Ruesch, 1996).

Regular fishing periods are Mondays and Fridays, and the fleet can fish anywhere in the Central District. The drift net fleet fishes primarily in the mid-channel and east-side rips. During periods of abundant returns to the Kenai and Kasilof Rivers, additional harvest periods are allowed in the Eastside Corridor (Trasky, 1995:5). The edge of the east rip is about five miles from shore and in a normal fishing period, this area is heavily used (KPBPC, 1994:10-11). Other rips in the inlet have been identified by the United Cook Inlet Drift Association (KPBPC, 1994:13). The set net fishery takes place along the entire east side of the upper inlet, from Ninilchik north to Boulder Point; on Kalgin Island; and along portions of the western shore of the inlet (Trasky, 1995:5).

b. Potential Conflicts

Activities associated with exploration, development and production of oil and gas may utilize portions of fisheries harvest zones. Commercial fishers have expressed concern that the presence of oil and gas industry activities will interfere with fishing and inadvertently alter the distribution of returning fish among users. Offshore platforms may create an obstacle to drift gillnet fishing. Semi-submersible drill rigs and anchoring systems could cause a loss of fishing space or impede access to the water column. Rig systems may require a one-mile radius for anchoring and safety. Trawl net gear loss has resulted from subsurface well heads on federal OCS leases off the coast of California. (Miles, et al., 1982:448).

Seismic Surveys. Seismic surveys using airguns to generate acoustic energy could affect fishing, because seismic noise may disperse herring or salmon and reduce a vessel's catch. Marine surveys deliver wave energy to the immediate area and for a few hours during survey operations. Seismic surveys that are planned and coordinated with the commercial fishing industry are expected to make conflicts rare to nonexistent (MMS, 1995: IV.B.1-73). In the past, seismic exploration cables up to 1.5 miles long have disrupted Tanner and King crab pot fisheries in Alaska, however, currently no pot fisheries occur in the sale area (Miles, et al., 1982:448).

Drilling and Production Discharges. Drilling discharges are not expected to affect commercial fishing due to the limited area affected near the platform-discharge point. Muds and cuttings are diluted to levels that are within the range of naturally occurring concentrations within a distance of between 100 and 200 meters from the discharge point (MMS, 1995:IV.B.1-8). Recently completed studies indicate some toxicity will occur within these mixing zones, but not at significantly harmful levels (See previous sections). Studies and initiatives are ongoing to detect industry emissions on Cook Inlet fish, sediments, and water.

Oil Spills. The greatest threat to commercial fishing is a large oil spill, with both gear and catch at risk. An oil spill could pose an even greater threat to future runs if juvenile salmon were present in the upper portion of the water column. Even if not contaminated by an oil spill, fish could be perceived as being contaminated. This typically leads to fishing closures, the loss of income, and marketing problems (MMS, 1995:IV.B.1-72). Not all large spills result in fishing closures and some small spills may require fishing closures during a response. Potential long term sub-lethal effects of an oil spill on fish include genetic impairment, overescapement and reduced fitness in juveniles. This may have long term impacts on the commercial salmon industry (ADF&G, 1996:3).

Navigation. Other conflict concerns relate to transportation and navigability of the Cook Inlet waterway, which is regulated by the U.S. Coast Guard. The U. S. Coast Guard has jurisdiction within Cook Inlet under the Ports and Waterways Safety Act (33 U.S.C. § 1223(c)(1)) which recognizes the paramount right of navigation over all other uses. The Coast Guard may designate port access routes and fairways under the Act. In other coastal states, like California, vessel traffic lanes are very close to federal oil leasing activities (Miles, et al., 1982:448). However, platform support vessels and platforms have provided communications and emergency assistance to commercial and recreational boats of the Pacific west coast (Miles, et al., 1982:452).

Potential Conflicts within the Fishing Corridor. The sale area includes a portion of the Eastside salmon harvest corridor (see Figure 5.3, Cook Inlet Fishing Corridor). During normal salmon fishing periods, and with the exception of river mouths, the drift fleet has unrestricted access to most of Cook Inlet, north of Anchor Point and south of the Forelands. On days other than Mondays and Fridays, fishers are concentrated in a three-mile corridor and may have less maneuvering space per vessel, especially along the corridor boundaries, Cape Kasilof, and The Sisters. Fishing vessels may come within close proximity to semi-submersible drill rigs, platforms or anchored construction barges associated with lease activities, especially in the vicinity of tide rips. However with controls in place, the potential for conflicts are minimized.

When fishermen encounter an object, they may have to pull in their gear until they pass by or maneuver about the object. Thus, a platform or temporary drilling unit would infringe to some extent on commercial fishing in the fishing corridor, but would not preclude commercial fishing entirely. Siting a offshore facilities outside of the fishing corridor would lessen the potential for interference on commercial fishing in Cook Inlet.

Specific areas where oil and gas, and commercial fishing industry activities may overlap or coincide include:

- approach lanes to ports used by tankers, barges, tugs, container ships.
- regulatory boundaries designed to control interception and harvest (fishing corridor).
- natural stationary features, like rocks and points where migrating salmon concentrate.
- tide rips associated with salmon concentration behavior.

c. Harvest Protection

Mitigation Measures

The following are summaries only. For a complete full-text listing of mitigation measures, see Chapter Nine. mitigation measures or regulatory provisions that would minimize impacts to commercial fishing include:

- Lease-related use will be restricted when the commissioner determines it is necessary to prevent unreasonable conflicts with local subsistence harvests and commercial fishing operations. In enforcing this term the division, during review of plans of operation or development, will work with other agencies and the public to assure that potential conflicts are identified and avoided. In order to avoid conflicts with fishing activities, restrictions may include alternative site selection, requiring directional drilling, seasonal drilling restrictions, subsea completion techniques, and other technologies deemed appropriate by the commissioner.
- Offshore pipelines must be located and constructed to prevent obstructions to marine navigation and fishing operations.
- Oil spill prevention -- Lessees are required to implement oil spill prevention, control, and countermeasures plans. In addition, they are required to site facilities away from lakes and streams and critical wetlands, that provide important rearing habitat for juvenile salmon.
- Habitat Protection -- lessees are prohibited from using explosives in open water areas of fishbearing streams and lakes which protects salmon habitat. The use of explosives for seismic activities with a velocity of greater than 3,000 feet per second in marine waters is prohibited.

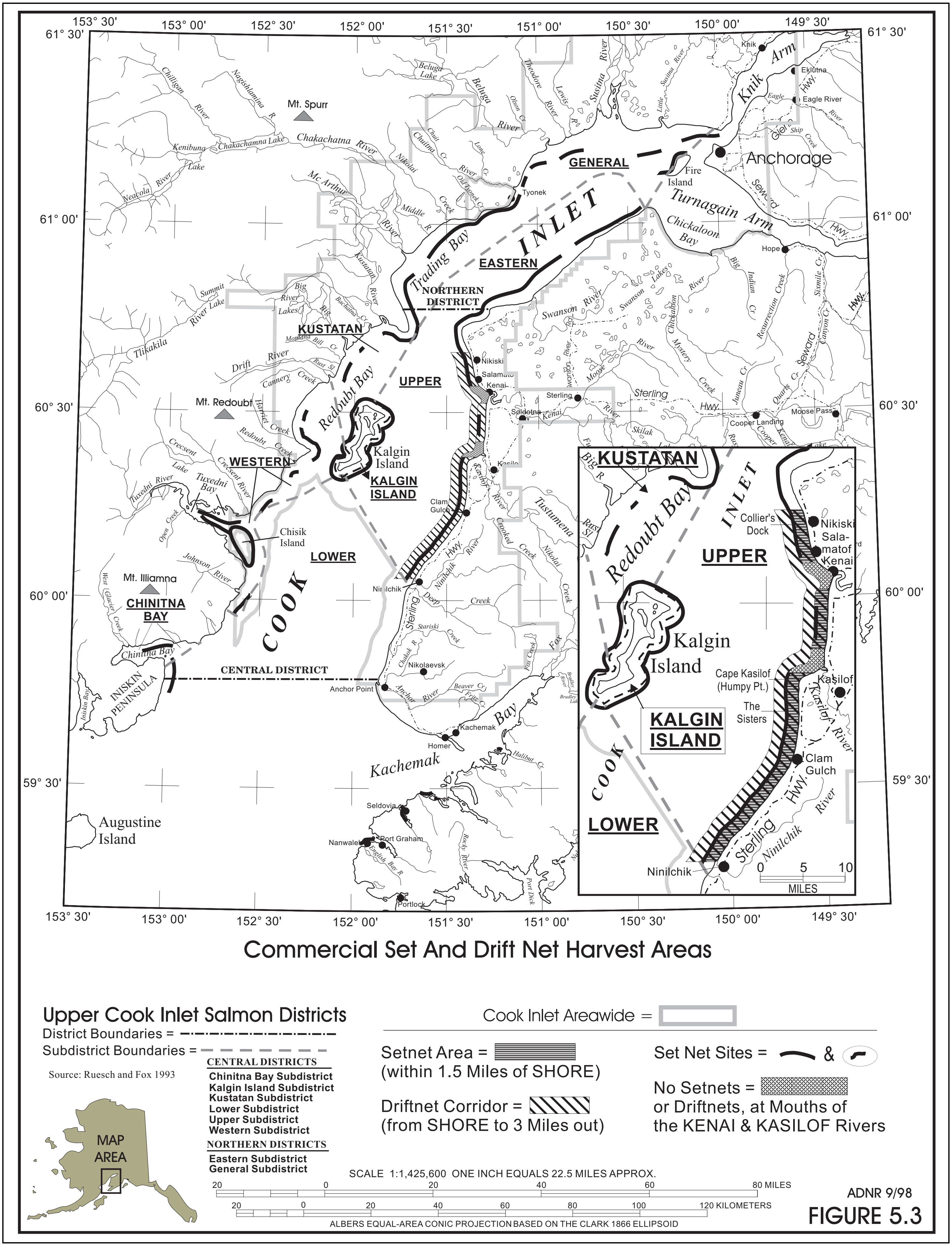

Commercial Set And Drift Net Harvest Areas
Upper Cook Inlet Salmon Districts
District Boundaries =
Subdistrict Boundaries =
Source: Ruesch and Fox 1993
CENTRAL DISTRICTS
Chinitna Bay Subdistrict
Kalgin Island Subdistrict
Kustatan Subdistrict
Lower Subdistrict
Upper Subdistrict
Western Subdistrict
NORTHERN DISTRICTS
Eastern Subdistrict
General Subdistrict
Cook Inlet Areawide =
Setnet Area =
(within 1.5 Miles of SHORE)
Driftnet Corridor =
(from SHORE to 3 Miles out)
Set Net Sites = &
No Setnets =
or Driftnets, at Mouths of
the KENAI & KASILOF Rivers
MAP AREA
SCALE 1:1,425,600 ONE INCH EQUALS 22.5 MILES APPROX.
80 MILES
120 KILOMETERS
ALBERS EQUAL-AREA CONIC PROJECTION BASED ON THE CLARK 1866 ELLIPSOID
ADNR 9/98
GENERAL
EASTERN
NORTHERN DISTRICT
KUSTATAN
UPPER
WESTERN
KALGIN ISLAND
LOWER
CHINITNA BAY
CENTRAL DISTRICT
COOK
INLET
Anchorage
Turnagain Arm
Knik Arm
Trading Bay
Redoubt Bay
Kalgin Island
Chisik Island
Augustine Island
Kachemak Bay
Mt. Spurr
Mt. Redoubt
Mt. Illiamna
Tyonek
Fire Island
Nikiski
Kenai
Soldotna
Sterling
Kasilof
Clam Gulch
Ninilchik
Anchor Point
Homer
Seldovia
Port Graham
Nanwalek
Portlock
Hope
Cooper Landing
Moose Pass
INISKIN PENINSULA
Collier's Dock
Cape Kasilof (Humpy Pt.)
The Sisters
MILES

FIGURE 5.3

d. Summary

Before a permit to explore or otherwise conduct lease-related activities in the inlet is issued by the DO&G, operators are required to consult with ADF&G regarding fishery harvest schedules. Seismic activities are often restricted to avoid conflict with subsistence fishing activities in upper Cook Inlet (Rader, 1996). Typical exploration permit terms require seismic operators to avoid operating in areas and at times the fisheries are most active so that harvest levels are not disrupted. Other fish harvest access protection measures may be required for consistency with the Alaska Coastal Zone Management Program. Lease mitigation measures, permit requirements, and direct communication between user groups should avert any conflict over access to the water column. In those instances where accommodation is impossible, the state retains the authority to disallow the proposed activity.

ADNR manages state lands and tidelands in conformance with the principles of multiple concurrent uses and access to public resources. The Alaska Constitution, as well as the Alaska Land Act and the ACMP contemplate that state land is available for "maximum use" and that there will be "reasonable concurrent uses." Alaska Constitution. art. VIII, §§ 1, 2, 8. In light of the lengthy history of oil and gas development in Cook Inlet it is unreasonable to assume that there is incompatibility between fishing, navigation, and future potential oil and gas development.

2. Recreation and Tourism

Recreation includes bicycling, canoeing, kayaking, sailing, river boating, sport fishing, sport hunting, flightseeing, horseback riding, photography, camping, snow machining, cross country skiing, day hiking, outback hiking, wildlife viewing, berry picking, and mountain climbing. All uses require some access to the outdoor environment. Many recreational uses involve public lands and depend on the use of public waterbodies.

As described in Chapter 1, while the sale area boundary encompasses approximately 4.2 million acres, the state may only lease lands in which it owns the subsurface estate (approximately 2.8 million acres). Where leasing does occur, recreational activities are not expected to be impacted by cumulative effects of the areawide lease sale because environmental laws, mitigation measures, and other restrictions protect areas used for recreation. Many mitigation measures protect recreational uses of public lands and waterbodies. Several special areas, such as the Anchor River and Fritz Creek CHA or the Trading Bay SGR, which support recreational activities, have additional restrictions and provisions to protect resource values. Recreational areas that get high use, like Chugach State Park, Clam Gulch CHA, or Kachemak Bay State Park, are either not available for lease or have a surface entry prohibition. Important recreational areas and tourist destinations are not likely to be affected by the sale. State and federal parks are excluded form leasing. Surface entry restrictions are imposed in state critical habitat areas and game refuges. All major projects proposed in the coastal zone must undergo an ACMP consistency review. See Chapter Nine for a complete full text listing of mitigation measures.

Access. If platforms were constructed offshore, some recreational marine boaters may have to avoid or navigate around such platforms. Facilities and operations may not be located so as to block access to or along navigable and public waters. Platforms may not be sited so as to obstruct navigable waters of Cook Inlet as determined by the USCG. Although just a portion of tracts overlap with this high use area, alternative sites or directional drilling may be required.

Public access to or use of the leased area shall not be restricted except within 1,500 feet or less of onshore drill sites, buildings and other related structures. Onshore access to public lands, streams and lakes may not be restricted unless there are no other feasible or prudent alternatives. No facilities other than docks or road and pipeline crossings may be sited within 500 feet of all fishbearing streams and lakes, unless there are no other alternatives. Additionally, siting of facilities will be prohibited within one-half mile of the banks of Harriet, Alexander, Lake, Deep, and Stariski Creeks, and the Drift, Big, Kustatan, McArthur, Chuitna, Theodore, Beluga, Susitna, Little Susitna, Kenai, Kasilof, Ninilchik, and Anchor Rivers. New facilities may be sited within the one-half mile buffer if the lessee demonstrates that the alternate location is environmentally preferable, but in no instance will a facility be located within one-quarter mile of the riverbank**.**

Temporary roads for exploration drilling may be built and subsequently removed or rehabilitated. Some permanent roads may be constructed as a result of proposed activity, and while these may serve to increase access to the environment, and have a positive impact on area recreation, they may also have an undesirable effect on community development, land use planning, or fish and game management.

If a development project were proposed and a plan of operations approved, it is possible that portions of some roads or trails may be temporarily closed during construction. Alternative access or detours may be required by the director before operations or land use permits may be approved. Plans of operation for projects on lease tracts must describe the lessee's efforts to communicate with communities and interested local community groups in the development of such plans. Lessees must include a training program for on-site personnel to increase sensitivity and understanding of community values, customs, and lifestyles in areas where they will be operating.

Habitat Loss. Some development, such as the construction of a gravel drill site may result in habitat loss and, although unlikely, could result in adverse impact on fish or wildlife populations which support a particular recreational activity, such as sport hunting. Some construction activities may temporarily disrupt wildlife viewing or permanently affect hunting in areas in close proximity to facilities or operations.

Lessees must avoid siting facilities in identified sensitive habitat areas, including key wetlands. The siting of facilities or operations which may block fish passage is prohibited. Alteration of river banks, operation of equipment within riparian habitats, and the operation of equipment, except for boats, in open water areas of rivers and streams are prohibited activities.

Economy. Many, if not most recreational uses involve cash transfers. The recreation and tourism industry in the Cook Inlet/Susitna areas is dependent on the use of the existing transportation systems and service providers. For example, recreation activities of many residents and non-residents in the area are supported by hotels and motels, fast food restaurants, specialty shops, supply stores, grocery stores, and large retail stores located along the Sterling, Seward, Glenn and Parks Highways. These businesses support recreation activities in high-use areas, such as the Kenai and Moose Rivers or Big Lake.

Any lease-related activity which reduces the recreationist's ability to access high-use areas, like the Kenai River, or reduces the ability to contract or employ services, such as a river guide service, could have adverse consequences on residents and the local economy. However, considering the current level of congestion on Kenai Peninsula highways and sport fishing pressure on area rivers during the summer, it is likely that any oil and gas activity associated with any leasing would have a negligible effect on recreation and its supporting economy and habitats. To the contrary, infrastructure development may provide a source of oil and gas property taxes that could be spent on new or existing recreation support facilities, like parking lots, camp sites, and rest rooms.

Tourism. Alaska visitor industry statistics suggest that tourism and oil & gas activities are compatible. (see Chapter Four for a summary of Alaska visitor statistics). Factors such as availability of transportation, accommodations, quantity and quality of food services, and the carrying capacity of attractions and transportation systems likely influence where tourists travel in Alaska more than other factors, such as ability to shop, or appeal of attractions. Whether visitors return to an area and what they say to other potential visitors after they leave Alaska may depend on these factors or other unknown reasons (McDowell, 1993).

The most influential impacts of oil and gas activities on the perceptions of tourists and residents alike would be an oil spill, such as the 1989 *Exxon Valdez* spill. Surprisingly, the number of tourists visiting Alaska did not decline, but jumped 14 percent in the year following the spill: the highest gain over a previous year between 1989 and 1995 (Carlson, 1996)(McDowell, 1995:19). Opinions regarding aesthetic quality vary widely, and the sight of a production platform in the Inlet, for example, may strike discord with some visitors, add to the allure for some, or result in passive indifference in others.

Activities that reduce the ability of tourists to access towns and areas, fishing grounds and camp sites could affect visitors' perceptions or spending and travel habits. Oil industry use of the services mentioned above which would otherwise provide services to tourists could also impact visitors' travel and spending habits while in Alaska, and affect their perceptions. Oil and gas activity may also keep service providers in business during the slow season, and may attract new businesses.

Adverse effects are not likely as most oil and gas construction activity would occur during winter months, during the off-season for tourism. Any foreseeable impact on existing accommodations, attractions, and transportation services, including cruise ship and air carriers should be scrutinized at the plan of operations permit phase. Like recreation, impacts to tourism are related to access, protection of supporting species and habitats, and capacity of existing transportation systems and service providers. Some tourism infrastructure, such as lodging and number of visitor attractions has expanded recently. While these may accommodate some tourism industry needs, human pressure on rivers continues to grow. The cumulative effect of oil and gas activities is more revenues to support tourism needs, such as maintaining parks, recreation sites, sanitary facilities, and roads.

Mitigation Measures

The following are summaries of some applicable mitigation measures. For a complete, full text listing of mitigation measures, see Chapter Nine. Mitigation measures and lessee advisories that would mitigate potential impacts to recreation and tourism include:

- Oil and gas activities are restricted in critical habitat areas and state game refuges.
- All fishbearing streams and lakes are protected by stream buffers. Alteration of stream banks or operation of equipment in riparian habitats is prohibited.
- Permanent facilities may not be sited within one-half mile of major rivers.
- Public access of the leased area may not be restricted, except within 1,500 feet or less of drill sites and facilities.
- No lease facilities or operations may block access to or along navigable and public waters.

3. Scenic Resources

Following is a discussion on how recognized scenic resources can be protected with examples from three oil and gas projects. For a discussion on the effects of oil and gas activities on tourism, see the following section.

Scenic Resource Evaluation. The entire coastline of the Cook Inlet basin holds an abundance of vistas, natural features, and man-made scenic resources of varying aesthetic value. Scenic resources may include wetlands, tideflats, beaches, vertical bluffs, rocky coasts, lakes, stream corridors, undulating hills, bays, and inlets. They may be enclosed in a wooded canopy or open with one or more unique natural features in view. Scenic resources may also include man-made attractions, such as the Anchorage skyline. The position of the observer is always key in characterizing scenic resources.

Scenic resource planning should be used as a guide in operations planning, facility design, and site selection for development projects that may affect viewsheds. While aesthetic value is essentially a subjective phenomena, some objective criteria could be used to rank the sensitivity of visual resources to development activities. Criteria for ranking scenic resources have been developed by Litton (1968), Mann (1975), and Clark (1977), and the U.S. Forest Service (1979).

Solutions. *Dauphin Island, Mobile Bay, Alabama.* Arco was successful in mitigating adverse effects on a fragile coastal marine environment from offshore development in the planning and development of its Dauphin Island natural gas project. Construction of a pipeline, several wellheads, and production platform adjacent to a barrier island was required to make the development economical.

Dauphin Island is home to several residents, and supports tourism and nearby oyster beds. To alleviate environmental and aesthetic concerns, a unique platform design was developed after a nine month planning process. First, the platform featured a rain roof to minimize discharge of contaminated rain runoff. The rain roof freed up precious deck space and allowed for color and texture scheming which changed the profile of the platform, making it appear less industrial. Second, the vent boom was placed at an angle hidden from island view. "This gave the platform a clean, box-shaped profile when seen by island residents and tourists." (JPT, January 1994:65) Third, a local architect produced a color scheme for the permanent production platform. "From a vantage point on the island's beaches, color templates were used to select a two-tone paint scheme. The platform legs were painted blue and the upper portion of the platform was painted light gray to help the structure blend better with the surrounding seascape." Fourth, an added measure was taken to reduce visual impacts at night. Light shields were designed to reduce glare and prevent light from being seen directly by residents of the island. Additionally, sections of lights were placed on different circuits, so that they could be turned off, and platform lighting could be limited to those areas where work was being done. Finally, the visual spectrum of the operation was minimized by drilling horizontal wells to reduce the total number of wellheads near the platform, and the pipeline connecting the platform to the sales point was also horizontally bored under the tideflats (JPT, 1994).

The Dauphin Island project received national recognition and awards for excellence by the National Ocean Industries Association, National Environmental Development Association, and became a top finalist in the EPA's Pollution Prevention Award. Critical to its success were planning meetings with community residents, Alabama state officials, and the seafood industry. The project was completed in 1991 (JPT, 1994).

Wytch Farm, UK. Environmental and aesthetic concerns also drove the planning and design of the Wytch Farm project; a reserve located under Poole Bay, about 100 miles southwest of London in the U.K. The area is noted for its outstanding natural beauty, landscape, and ecology (JPT, 1995:414). The construction of an offshore production island was avoided by utilizing horizontal and extended-reach drilling (ERD) technology (See Chapter 6). As a result, onshore production facilities were necessary. To protect the environmentally sensitive nature of the area, all facilities were built low in profile and carefully integrated into the surrounding landscape using topography, color treatment of surfaces, and planting of local species. To assure that leaks of fluids were avoided, wellsites were lined with heavy-duty butyl liners. To ensure proper screening and landscaping at the site, an additional two acres of land were leased for every acre under development. Noise restrictions were imposed which required all permanent and mobile equipment to be extensively soundproofed (JPT, 1995:414).

Occidental Block 15, Ecuador. Environmental and aesthetic concerns expressed by local communities in the rain forests of eastern Ecuador were instrumental in the planing and design of a central production facility and a 16 mile pipeline. To minimize disturbance of surface vegetation, pipelines were buried, and multi-deviated wells were drilled close together from a central drillpad. All flow and gathering lines were buried with internal and external corrosion protection. Gas was flared horizontally in a smokeless flare that was invisible to nearby communities. The plume of a traditional stack-type gas flare can be seen for miles. All trees that had to be cut down were inventoried and trees of the same species planted after construction was complete. In order to minimize impacts from its seismic program to the protected area of the block, Limnococha Biological Reserve, Occidental developed an environmental management plan with monitoring and feedback mechanisms. This included construction of an environmental information management system which provides managers with basic tools to monitor and gauge the environmental effects of any of the company's or its contractor's operations (OGJ, 1997b).

Protection of Scenic Resources. Some visual management considerations developed by Mann (1975) include:

- Adopt site selection and site design criteria for facilities within the shoreline view area;
- Require building setbacks of 100 feet and minimum vegetative screen depths of 50 feet in residential bluff areas;
- Require building mass and color to be compatible with shorescape qualities;
- Require advertising and utility line controls in viewshed areas;
- Acquire title and easements to protect and provide public access to important scenic viewpoints and adjacent areas;
- Facilitate removal or enhancement of eyesores.

Additional measures specific to oil and gas activities may also be applied:

- Pipeline burial;
- Use of rain roofs, and light shields;
- Build facilities low in profile and integrate into surrounding landscape;
- Soundproofing of equipment;
- Horizontal flaring of gas, smokeless flares, and angled vent booms;
- Revegetate areas with local species;
- Use directional, horizontal, and extended-reach drilling where feasible.

The use of Extended-Reach Drilling (ERD) and directional or horizontal drilling may alleviate all concerns over aesthetic impacts, however applicability of ERD technology is limited and depends on contractor and drilling experience specific to individual oil or gas fields. For a description of directional, horizontal, and ERD applications and constraints, see Chapter Six.

Conclusion. Determining aesthetic value of scenic resources involves landscape planning, field studies, opinion surveys, and consensus building among public and private participants. Through the evaluation process, viewshed sensitivity can be ascertained and appropriate mitigation measures taken to address concerns.

While some may perceive the presence of development structures as intruders to scenic resources, others may not. It is clear that there is beauty in "pristine" vistas where there is a complete absence or perceived absence of human influence, and such vistas should be preserved for the benefit of society. However, aesthetic beauty also includes historical, cultural, and man-made influences on the natural world.

As the above cases demonstrate, mitigation of viewshed impacts is entirely project-specific and cannot be accomplished at the lease sale stage because no specific project has been proposed. When a review of a project's impact on scenic resources is warranted, concerns and input of community members is fundamental to the success of the development project.

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